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NUREG-2211

Safety Evaluation Report

Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1

Docket Number 50-416

Entergy Operations, Inc.

Office of Nuclear Reactor Regulation

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Manuscript Completed: October 2016
Date Published: November 2016

Office of Nuclear Reactor Regulation

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Grand Gulf Nuclear Station, Unit 1 (GGNS), license renewal application (LRA) by the United States (US) Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated October 28, 2011, Entergy Operations, Inc. (Entergy or the applicant) submitted the LRA in accordance with Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations*. Entergy requests renewal of the GGNS operating license (Operating License No. NPF-29) for a period of 20 years beyond the current expiration at midnight November 1, 2024.

GGNS is located approximately 20 miles southwest of Vicksburg, MS. The NRC issued the GGNS construction permit on September 4, 1974, and operating license on November 1, 1984. GGNS is of a boiling water reactor design. General Electric supplied the nuclear steam supply system and Allis-Chalmers Power Systems furnished the turbine generator set. The containment is a steel-lined reinforced concrete structure designed by Bechtel Power Corporation. The GGNS licensed power output is 4,408 megawatt thermal.

Unless otherwise indicated, this SER presents the status of the staff's review of information submitted through October 3, 2016, the cutoff date for consideration in the SER. The four open items previously identified in the SER with Open Items, issued January 31, 2013, have been closed (see Section 1.5); therefore, no open items remain to be resolved before the final determination is reached by the staff on the LRA.

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ABBREVIATIONS

AC	alternating current
AAI	applicant action item
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agency wide Document Access and Management System
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
ANSI	American National Standards Institute
APEC	area potential earth current
APRM	average power range monitor subsystem
ART	adjusted reference temperature
ASME	American Society of Mechanical Engineers
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 and Internals Project
CAP	corrective action program
CASS	cast austenitic stainless steel
CB&I	Chicago Bridge & Iron
CFR	*Code of Federal Regulations*
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CMTR	certified material test report
CPF	conditional probability of failure
CRD	control rod drive
CS	core spray
CST	condensate storage tank
CUF	cumulative usage factor
CUF_{en}	fatigue cumulative usage factor
CRW	clean radwaste
CUI	corrosion under insulation
CW	circulating water
DBA	design basis accident
DBE	design basis event
DM	dissimilar metal
EAF	environmentally assisted fatigue
ECCS	emergency core cooling system
ECP	electrochemical corrosion potential
EDG	emergency diesel generator
EFPY	effective full-power year

EIC	electrical and instrumentation and control
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ER	Environmental report (Applicant's Environmental Report Operating License Renewal Stage)
ESF	engineered safety features
F_{en}	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission
FR	*Federal Register*
FSAR	final safety analysis report
FW	feedwater
GALL	Generic Aging Lessons Learned Report
GDC	general design criteria or general design criterion
GE	General Electric
GEH	General Electric-Hitachi
GEIS	generic environmental impact statement
GGNS	Grand Gulf Nuclear Station, Unit 1
GL	generic letter
GSI	generic safety issue
HELB	high-energy line break
HPCS	high-pressure core spray
HVAC	heating, ventilation, and air conditioning
HWC	hydrogen water chemistry
I&C	instrumentation and controls
I&FE	inspection and flaw evaluation
IASCC	irradiation assisted stress-corrosion cracking
ICMH	in-core monitoring housing
ID	inside diameter
IGA	intergranular attack
IGSCC	intergranular stress-corrosion cracking
IHSI	induction heating stress improvement
IN	information notice
INPO	Institute of Nuclear Power Operations
ILRT	integrated leakage rate test
IPA	integrated plant assessment
IRM	intermediate range monitor subsystem
ISG	interim staff guidance
ISI	inservice inspection
ISP	Integrated Surveillance Program
kV	kilo-volt
LAR	license amendment request
LBB	leak-before-break
LER	licensee event report
LLRT	local leakage rate test

LOCA	loss-of-coolant accident
LPCI	low-pressure coolant injection
LPCS	low-pressure core spray
LPRM	local power range monitor
LRA	license renewal application
LRT	leakage rate test
LTOP	low-temperature overpressure protection
MC	metal containment
MCM	thousand circular mils
MEA	material, environment, aging effect
MeV	megaelectron volt
MoS_2	molybdenum sulfide
MSIV	main steam isolation valve
MSL	main steam line
mV	millivolt
MWt	megawatts-thermal
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
NMCA	noble metal chemical application
NPS	nominal pipe size
NRC	US Nuclear Regulatory Commission
NWC	normal water chemistry
OEP	Operating Experience Program
P&ID	plant piping and instrumentation drawing
PH	precipitation-hardened
ppm	parts per million
P-T	pressure-temperature
PTLR	Pressure-Temperature Limits Report
PTS	pressurized thermal shock
PWR	pressurized water reactor
PWSCC	primary water stress-corrosion cracking
QA	quality assurance
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
RFPT	recirculation feed pump turbine
RG	regulatory guide
RHR	residual heat removal
RI-ISI	risk-informed inservice inspection

RPV	reactor pressure vessel
RV	reactor vessel
RVI	reactor vessel internal(s)
RWCU	reactor water cleanup
RWST	refueling water storage tank
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SCRAM	emergency reactor shutdown
SE	safety evaluation
SER	safety evaluation report
SGTS	standby gas treatment system
SLC	standby liquid control
SRM	source range monitor
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SS	stainless steel
SRV	safety relief valve
SSC	system, structure, and component
SSES	Susquehanna Steam Electric Station
SSW	standby service water
TIP	traversing in-core probe
TLAA	time-limited aging analysis
TS	technical specification(s)
UFSAR	updated final safety analysis report
US	United States
USE	upper-shelf energy
UT	ultrasonic examination
UV	ultraviolet
VFLD	vessel flange leak detection
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 Grand Gulf Nuclear Station, Unit 1 (GGNS), as filed by Entergy Operations, Inc. (Entergy or the applicant). By letter dated October 28, 2011, Entergy submitted its application to the United States (US) Nuclear Regulatory Commission (NRC) for renewal of the GGNS's operating license for an additional 20 years. The NRC staff (the staff) prepared this report to summarize the results of its safety review of the LRA for compliance with Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54). The NRC project manager for the license renewal review is Emmanuel Sayoc. Mr. Sayoc may be contacted by telephone at 301-415-4084 or by electronic mail at Emmanuel.Sayoc@nrc.gov. Alternatively, written correspondence may be sent to the following address:

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In its October 28, 2011, submission letter, the applicant requested renewal of the operating license[s] issued under Section 103 (Operating License No. NPF-29) of the Atomic Energy Act of 1954, as amended, for GGNS for a period of 20 years beyond the current expiration at midnight November 1, 2024. GGNS is located approximately 20 miles southwest of Vicksburg, MS. The NRC issued the GGNS construction permit on September 4, 1974, and the operating license on November 1, 1984. GGNS is a boiling water reactor design. General Electric supplied the nuclear steam supply system and Allis-Chalmers Power Systems furnished the turbine generator set. The containment is a steel-lined reinforced concrete structure designed by Bechtel Power Corporation. The GGNS licensed power output is 4,408 megawatt 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 review of safety and environmental issues. 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 GGNS 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 October 3, 2016. 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 / 800-397-4209), and at the Harriette Person Memorial Library, 606 Main St., Port Gibson, MS 39150. 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 GGNS's proposed operation for an additional 20 years beyond the term of the current operating license. 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), dated 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 conclusions of this SER are in Section 6.

SER Appendix A is a table showing the applicant's commitments for renewal of the operating license. 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 issued a 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 GGNS.

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* (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 period of initial license 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, in 60 FR 22461, amended 10 CFR Part 54 establishes a regulatory process that is simpler, more stable, and more predictable 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 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 in order to fulfill NRC responsibilities under the National Environmental Policy Act of 1969. In June 2013, the staff revised and updated the environmental protection regulations (10 CFR Part 51) and issued a revised GEIS (GEIS, Revision 1) to incorporate lessons learned and knowledge gained from previous plant-specific environmental reviews. The revisions identify 78 environmental impact issues for consideration in license renewal environmental reviews, 59 of which have been determined to be generic to all plant sites.

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, pressurized thermal shock, anticipated transient without scram, and station blackout.

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.

Pursuant to 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 utilized the process defined in NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," dated 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 is also 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

Part 51 of 10 CFR contains regulations on environmental protection. 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 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 reviewed the plant-specific environmental impacts of license renewal, including whether there was new and significant information not considered in the GEIS. As part of its scoping process, the staff held a public meeting on January 31, 2012, at Port Gibson City Hall, to identify plant-specific environmental issues. The draft, plant-specific GEIS Supplement documented the results of the environmental review and made a preliminary recommendation as to the license renewal action. The staff held another public meeting to discuss the draft, plant-specific GEIS Supplement. The staff published the final, plant-specific GEIS Supplement separately from this report, after considering comments on the draft.

1.3 Principal Review Matters

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

Pursuant to 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.

Pursuant to 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 license renewal applications include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewal license." The current indemnity agreement (No. B-72) for GGNS states in Article VII that the agreement shall terminate at the time of expiration of the license specified in Item 3 of the Attachment to the agreement, which is the last to expire. Item 3 of the Attachment to the indemnity agreement, as revised by Amendment No. 4, lists GGNS operating license number NPF-29. The applicant requests that any necessary conforming changes be made to specify the extension of the agreement until the expiration of the renewed GGNS facility operating license sought in the application. In addition, should the license number change upon issuance of the renewed license, the applicant requests that conforming changes be made to Item 3 of the Attachment, and other sections of the indemnity agreement, as appropriate. 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.

Pursuant to 10 CFR 54.21, "Contents of Application - Technical Information," the NRC requires that the LRA contain (a) an integrated plant assessment, (b) a description of any CLB changes during the staff's review of the LRA, (c) an evaluation of TLAAs, and (d) a 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).

Pursuant to 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 letters dated August 15, 2012, October 25, 2013, October 27, 2014, and December 10, 2015, the applicant submitted LRA updates which summarized the CLB changes that have occurred during the staff's review of the LRA. These submissions satisfy 10 CFR 54.21(b) requirements.

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) that are 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 GGNS operating license. This statement adequately addresses the 10 CFR 54.22 requirement.

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," the 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
"Aging Management of Stainless Steel Structures and Components in Treated Borated Water, Revision 1" (LR-ISG-2011-01)	This LR-ISG provides guidance as to an acceptable approach for managing the effects of aging during the period of extended operation for stainless steel structures and components exposed to treated borated water within the scope of 10 CFR Part 54.	SER Section 3.5.2.1.10
"Aging Management Program for Steam Generators" (LR-ISG-2011-02)	This LR-ISG evaluates the suitability of using Revision 3 of NEI 97-06 for implementing the steam generator AMP.	N/A for the SER
"Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks'" (LR-ISG-2011-03)	This LR-ISG provides an acceptable approach for managing the effects of aging of buried and underground piping and tanks within the scope of 10 CFR Part 54.	SER Section 3.0.3.1.4
"Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors" (LR-ISG-2011-04)	This LR-ISG revises the recommendations in the GALL Report and the staff's acceptance criteria and review procedures in the SRP-LR to ensure consistency with Materials Reliability Program (MRP)-227-A. This LR-ISG also	N/A for the SER

ISG Issue (Approved ISG Number)	Purpose	SER Section
	provides a framework to ensure that PWR LRAs will adequately address age-related degradation and aging management of reactor vessel internal (RVI) components during the term of the renewed license.	
"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 1.5, 3.0.5.2, 3.0.5.2.2 and 3.0.5.3
"Wall Thinning Due to Erosion Mechanisms" (LR-ISG-2012-01)	This LR-ISG provides guidance on an acceptable approach to manage the effects of aging during the period of extended operation for wall thinning due to various erosion mechanisms for piping and components within the scope of 10 CFR Part 54. This LR-ISG also GALL Report AMP XI.M17, "Flow-Accelerated Corrosion."	SER Section 3.0.3.1.21
"Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (LR-ISG-2012-02)	This LR-ISG revises existing guidance in the GALL Report and SRP-LR related to aging management of internal surfaces of components and atmospheric storage tanks. Also, it provides recommendations for corrosion under insulation of component external surfaces.	SER Section 3.0.3.1.17, 3.0.3.2.2, 3.2.2.2.8, 3.3.2.2.7, 3.3.2.3.7, 3.4.2.2.5, and 3.4.2.3.2
"Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks" (LR-ISG-2013-01)	This LR-ISG provides an acceptable approach for managing these associated aging effects for components within the scope of license renewal.	SER Section 3.0.3.1.20, 3.0.3.3.1, 3.0.3.3.2, and 3.0.3.3.3

LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations," was issued final on February 4, 2015, coincident with the final concurrence process of the SER. The staff concluded that the changes in the ISG do not affect the staff's conclusions related to the applicant's Buried Piping and Tanks Inspection Program documented in SER Section 3.0.3.1.4. The staff based its conclusion on a review of the changes in LR-ISG-2015-01. For example, the ISG: (a) reduced the number of recommended inspections of buried piping from that cited in the applicant's program; (b) provided further options for cathodic protection acceptance criteria, but retained the former criteria; and (c) recommended that underground steel components be coated; however, as documented in SER Section 3.0.3.1.4, the applicant's underground components are coated.

1.5 Summary – Closure of Open Items

As a result of its review of the LRA, including additional information submitted through October 3, 2016, the staff closed the following open items previously identified in the "Safety

Evaluation Report with Open Items Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1," dated January 31, 2013 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13032A194). No other open items remain to be addressed. An item is considered open if the staff has not made a finding under 10 CFR 54.29 (Standards for issuance of a renewed license) with respect to that particular item. A summary of the basis for each closed open item is presented here.

Open Item 3.0.3.1.33-1 One-Time Inspection – Small-Bore Piping

As described in SER Section 3.0.3.1.33, the GGNS operating experience review of the previous 10 years of condition reports does not fully demonstrate consistency with GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping." As described in SER Section 3.0.3.1.33, the staff determined that it needs the methodology and results of an applicant review of the period of plant operation leading up to the 10-year period covered in the previous review. This information is necessary to demonstrate that the one-time inspections recommended by GALL Report AMP XI.M35 will ensure that the effects of aging will be adequately managed for ASME Code Class 1 small-bore piping.

By letter dated April 15, 2013, the applicant stated that it completed an additional search of condition reports for the period beginning from the start of licensed operation of GGNS. Based on this additional search, the applicant stated that it identified no instances of age-related cracking of ASME Code Class 1 small-bore piping. The staff reviewed the applicant's search methodology and results and determined that they are satisfactory. Because the applicant reviewed plant-specific operating experience covering the full operating history of the plant, and this review identified no instances of age-related cracking of ASME Code Class 1 small-bore piping, the staff determined that the applicant has demonstrated applicability of GALL Report AMP XI.M35 to GGNS. As such, the staff finds that the applicant's One-Time Inspection – Small-Bore Piping Program is consistent GALL Report AMP XI.M35 and will ensure that the effects of aging will be adequately managed for ASME Code Class 1 small-bore piping. Open Item 3.0.3.1.33-1 is closed.

Open Item 3.0.3.1.39-1 Service Water Integrity

As described in SER Section 3.0.3.1.39, recent GGNS plant-specific operating experience condition reports discuss minor erosion to a valve flange connection in the standby service water (SSW) system. Proposals were made to include this valve in an "appropriate piping program" (GGNS MS-46, "Project Plan for Monitoring Internal Erosion/Corrosion in Moderate Energy Piping Components"). Although the program plan identified the SSW system as a susceptible system in the moderate energy program, it was not clear to the staff whether components in the SSW system were being managed for loss of material due to erosion because it is not described in the LRA nor discussed in the onsite program evaluation documentation.

The applicant addressed the issues associated with Open Item 3.0.3.1.39-1 in its response to RAI B.1.41-3c, dated December 20, 2013. The applicant revised LRA Sections A.1.41 and B.1.41 to state that the Service Water Integrity Program also includes inspections for loss of material due to erosion and included a new enhancement to revise program documents to include inspections for this aging mechanism. In separate correspondence associated with a Predecisional Enforcement Conference, dated August 8, 2013, the applicant stated that its previous response had incorrectly stated that GGNS-MS-46 is not credited for managing loss of material due to erosion. As part of the current response, the applicant stated that it had identified discrepancies in the GGNS-MS-46 database during the development of its RAI response and this condition had been entered into its corrective action program. On the basis of the staff's evaluation of the applicant's responses, Open Item 3.0.3.1.39-1 is closed. The staff's resolution and closure of this issue is documented in SER Section 3.0.3.1.39.

Open Item 3.0.5-1 Operating Experience for Aging Management Programs

As described in SER Section 3.0.5, the staff determined that the applicant's programmatic activities for the ongoing review of operating experience were consistent with the guidance in SRP-LR Section A.4.2, as established in LR-ISG-2011-05, with the exception of those activities associated with (1) identification of age-related operating experience, (2) evaluation of AMP implementation results, (3) content of personnel training, and (4) operating experience reporting. These four areas were the subject of Open Item 3.0.5-1.

Based on its review of additional information provided by the applicant in letters dated April 15, 2013, and October 11, 2013, the staff determined that the applicant's activities for (1) identification of age-related operating experience, (2) evaluation of AMP implementation results, and (3) the content of its personnel training are consistent with the guidance in SRP-LR Section A.4.2. The staff ultimately determined that the applicant's activities associated with operating experience reporting are not consistent with the guidance in SRP-LR Section A.4.2. However, the staff determined that this inconsistency is an acceptable departure from the guidance because these reporting activities would not directly facilitate the applicant's ability to maintain the effectiveness of its own AMPs. Based on the completion of its review, the staff determined that the applicant's programmatic activities for the ongoing review of operating experience are acceptable because they provide 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) the enhancement of AMPs 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. Open Item 3.0.5-1 is closed.

Open Item 4.2.1-1 Reactor Vessel Fluence

The staff reviewed the applicant's fluence analysis for the reactor vessel, consistent with the review procedures in SRP‑LR Section 4.2, which indicates that the applicant identifies (a) the neutron fluence for the reactor vessel at the expiration of the license renewal period; (b) the staff‑approved methodology used to determine the neutron fluence; and (c) whether the method follows the guidance in NRC RG 1.190.

In its review, the staff determined that the applicant's fluence method was inconsistent with NRC RG 1.190. RG 1.190 does not address the use of a method combining fluence results from two different methods. As a result, the staff requested a sufficient technical basis for combining the fluence results in order to ensure adequate analytic uncertainty analysis. Alternatively, the staff requested the applicant to provide results from a single method which is within the scope of RG 1.190.

The staff also noted that the method used to perform the MPM pre-EPU fluence calculations is not documented in an NRC-approved method. Therefore, the staff noted that a detailed description of the calculational method, and their qualification, as both pertain to GGNS, must be submitted for NRC staff review and approval for referencing in the LRA.

As described in SER Section 4.2.1, the staff finds that the applicant's response is acceptable because (1) the applicant provided the relevant reference to the staff-approved single fluence method (i.e., MPM method) that was approved in the staff's August 18, 2015, safety evaluation (SE), (2) the approved method, consistent with RG 1.190, was incorporated into the current licensing basis by License Amendment No. 204, and (3) the additional actions of the applicant, which are specified in the staff's August 18, 2015, SE, will ensure adequate qualification of the fluence method for the locations outside the original beltline region (e.g., comparison of fluence calculations with dosimetry measurements at core shroud locations above the active core region).

Additionally, the staff finds that the applicant adequately evaluated the TLAA for the reactor vessel neutron fluence because (1) the applicant adequately identified neutron fluence calculations as a neutron embrittlement TLAA, (2) the applicant incorporated the staff-approved fluence method into the current licensing basis through the license amendment process, (3) the applicant performed 54-EFPY (effective full-power year) fluence calculations in accordance with the staff-approved method that is consistent with the guidance in RG 1.190, and (4) the applicant's analysis provides neutron fluence projections to the end of the period of extended operation (54 EFPY). Open Item 4.2.1-1 is closed.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA, including additional information submitted through October 3, 2016, the staff determines that no confirmatory items exist which 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.

License Condition No. 1:

The information in the UFSAR supplement, submitted pursuant to 10 CFR 54.21(d), as revised during the LRA review process, and licensee commitments as listed in Appendix A of the "Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1," are collectively the "License Renewal UFSAR Supplement." This supplement is henceforth part of the UFSAR, which will be updated in accordance with 10 CFR 50.71(e). As such, the licensee may make changes to the programs, activities, and commitments described in this Supplement, provided the licensee evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

License Condition No. 2:

The "License Renewal UFSAR Supplement," as updated by license condition [1] above, 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 the period of extended operation.

(b) The applicant shall complete those activities by the 6-month date prior to the period of extended operation or the end of the last refueling outage prior to the period of extended operation, whichever occurs later.

(c) 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.

The purpose of requiring the completion of implementation, inspection, and testing, either before the end of the last refueling outage or before the 6-month time frame, is to ensure that the implementation of programs and completion of specific activities can be confirmed by the staff's oversight process before each plant enters its respective period of extended operation.

LRA Appendix A, Section A.5, "License Renewal Commitment List," contains commitments for license renewal and an associated schedule for when the applicant plans to implement or complete the commitments. Through the commitments in LRA Appendix A, Section A.4, the applicant will implement new programs and enhancements to existing programs and will also complete inspection or testing activities. Because the applicant's implementation schedule for some commitments, as provided originally in LRA Appendix A, Section A.5, could conflict with the implementation schedule intended by the generic second license condition described above, by letter dated November 21, 2013, the staff issued RAI A.1-1, which requested that the applicant provide the expected date for implementing all commitments prior to the period of extended operation and state whether the implementation would be documented as a license condition or as a supplement to the UFSAR. By letter dated December 20, 2013, the applicant responded to RAI A.1-1 and provided a revision to LRA Appendix A, in which it specified the time period when each commitment would be implemented and where it would be documented.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10, Section 54.21, “Contents of Application Technical Information,” of the *Code of Federal Regulations* (10 CFR 54.21) requires 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 2.0, “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 that Entergy Operations, Inc., System Energy Resources, Inc., and South Mississippi Electric Power Association (collectively, the applicant) used to identify the SSCs at the Grand Gulf Nuclear Station (GGNS) within the scope of license renewal (scoping) and the SCs subject to an AMR (screening).

LRA Section 2.1.1, “Scoping Methodology,” states, in part, that the applicant had considered the following in developing the scoping and screening methodology described in LRA Section 2.0:

- 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,” dated June 2005 (NEI 95-10)

2.1.3 Scoping and Screening Program Review

The United States (US) Nuclear Regulatory Commission (NRC) staff (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 plant 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)(1) and (a)(2), as they relate 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 (1) SSCs that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and (2) 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 GGNS facility located in Port Gibson, Mississippi, during the week of January 9–12, 2012. 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 implementation and control of the license renewal, the quality practices the applicant used during the LRA development, and the training of its personnel that participated in the LRA development. On a sampling basis, the staff performed a review of scoping and screening results report and supporting current licensing basis (CLB) information for the standby service water (SSW) system and the turbine building. In addition, the staff performed walkdowns of selected portions of the SSW system 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

2.1.3.1.1 Summary of Technical Information in the Application

The applicant had developed scoping and screening implementing procedures used to identify SSCs within the scope of license renewal and SCs subject to an AMR to implement the processes described in LRA Sections 2.1 and 2.2. Additionally, the applicant's implementing procedures provided instruction on the review and consideration of CLB documentation sources, relative to the requirements of 10 CFR 54.4 and 10 CFR 54.21.

LRA Section 2.1 listed the following information sources used by the applicant during the license renewal scoping and screening process:

- updated final safety analysis report (UFSAR)
- GGNS equipment database
- design basis documents
- maintenance rule basis documents
- technical specifications (TS)
- fire hazards analysis
- engineering drawings

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 "Scoping and Screening Methodology Audit Report Regarding the Grand Gulf Nuclear Station, Unit 1 License Renewal Application," to ensure the guidance is consistent with the requirements of the Rule, the SRP-LR, and Regulatory Guide (RG) 1.188, which endorses the use of NEI 95-10. The staff determined that the overall process used to implement the 10 CFR Part 54 requirements described in the implementing procedures and AMRs was consistent with the Rule, the SRP-LR, and the endorsed industry guidance.

The applicant's implementing procedures contained guidance for identifying plant SSCs within the scope of the Rule and SCs, contained in systems within the scope of license renewal, which 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 July 12, 2012, to the staff's requests for additional information (RAIs) dated June 15, 2012.

After reviewing the LRA and supporting documentation, the staff determined that the scoping and screening methodology implementing procedures are consistent with the methodology description provided in LRA Section 2.1, and 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 Current Licensing Basis Information. 10 CFR 54.21(a)(3) requires, for each SC determined to be subject to an AMR, that the applicant 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. Section 54.3(a) of 10 CFR Part 54 defines the CLB, in part, as the set of NRC requirements applicable to a specific plant and a licensee'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, TS, 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 (GLs), and enforcement actions, and licensee commitments documented in NRC safety evaluations (SEs) or licensee event reports. The staff considered the scope and depth of the applicant's CLB review to verify that the methodology is sufficiently comprehensive to identify SSCs within the scope of license renewal and as SCs requiring an AMR.

During the scoping and screening methodology audit, the staff determined 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 the applicant used, including the UFSAR, design basis documents, the equipment database, 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 maintenance rule basis documents, TS, and the fire hazards analysis.

The equipment database, UFSAR, and plant drawings were the applicant's primary repository for system identification and component safety classification information. During the audit, the staff discussed the applicant's administrative controls for the equipment database and 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 determined that the applicant has established adequate measures to control the integrity and reliability of system identification and safety classification data and, therefore, 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 listing 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 consistent with the plant's CLB.

2.1.3.1.3 Conclusion

Based on its review of LRA Section 2.1, the detailed scoping and screening implementing procedures and the results from the scoping and screening methodology 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 employed to develop the LRA were adequate for the activity. The applicant used the following quality control processes during the LRA development:

- performed scoping and screening activities using approved documents and procedures
- employed databases to guide and support scoping and screening activities and generate license renewal documents. These databases included
  - Equipment Database (EDB) – A database used as the central repository of equipment-specific information
  - License Renewal Information System (LRIS) – A database used primarily for IPA activities of scoping and developing AMR reports

During the scoping and screening methodology audit, the staff performed a sample review of implementing procedures and guides, examined the applicant's documentation of activities contained in reports, reviewed the applicant's activities performed to assess the quality of the LRA, and held discussions with the applicant's license renewal management and license renewal project personnel. The staff determined that the applicant's activities provide assurance that the LRA was developed consistent 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 meet current regulatory requirements and 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 training process the applicant used for license renewal project personnel. As outlined in the implementing procedures, the applicant had required training for personnel participating in the development of the LRA and used trained and qualified personnel to prepare the scoping and screening implementing procedures.

The license renewal project personnel had been trained to the applicable project procedures and other relevant license renewal information using the applicant's License Renewal Overview and Project Plan, as appropriate to their functions. Training topics had included 10 CFR Part 54, relevant NRC and industry guidance documents, lessons learned from other nuclear power plant license renewals, and applicable implementing procedures. The training had been accomplished primarily by classroom instruction and reviewing documents and was documented on forms developed for that purpose.

The staff discussed training activities with the applicant's management and license renewal project personnel and performed a sampling review of applicable documentation. The staff determined that the applicant had developed and implemented adequate controls for the training of personnel performing LRA activities.

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 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, and the results from the scoping and screening methodology audit, 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 2.1.1, “Scoping Methodology,” described the applicant’s methodology used to scope SSCs 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 or support an intended function for responding to a design basis event (DBE); are nonsafety-related but their failure could prevent accomplishment of a safety-related function; or support a specific requirement for one of the five regulated events applicable to license renewal. LRA Section 2.1.1 also states that the scoping methodology GGNS used is consistent with 10 CFR Part 54 and 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 2.1.1.1, “Application of Safety-Related Scoping Criteria,” which states in part:

> A system or structure is within the scope of license renewal if it performs a safety function during and following a design basis event as defined in 10 CFR 50.54(a)(1).
>
> [The applicant’s] procedure provides the criteria and methodology for determining and evaluating the safety and quality classification of systems, structures and components. The procedure defines design basis events consistent with 10 CFR 50.49 (b)(1) and defines safety-related, or quality assurance Category SR, to include those structures, systems and components that are relied upon to remain functional during and following design basis events to assure the following:
>
> - The integrity of the reactor coolant pressure boundary; or
> - The capability to shut down the reactor and maintain it in a safe shutdown condition; or
> - The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the applicable guideline exposures set forth in 10 CFR 50.34(a)(1), 10 CFR 50.67, or 10 CFR 100.11, as applicable.

2.1.4.1.2 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(1), the applicant must consider all safety-related SSCs relied upon to remain functional during and following a DBE to ensure the following functions: (1) the integrity of the reactor coolant pressure boundary (RCPB), (2) the ability to shut down the reactor and maintain it in a safe shutdown condition, or (3) 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, as applicable.

With regard to identification of DBEs, Section 2.1.3, “Review Procedures,” of the SRP-LR states:

> The set of design basis events as defined in the rule is not limited to Chapter 15 (or equivalent) of the UFSAR. Examples of design basis events that may not be described in this chapter include external events, such as floods, storms, earthquakes, tornadoes, or hurricanes, and internal events, such as a high energy line break. Information regarding design basis events as defined in 10 CFR 50.49(b)(1) may be found in any chapter of the facility UFSAR, the Commission's regulations, NRC orders, exemptions, or license conditions within the CLB. These sources should also be reviewed to identify systems, structures, and components that are relied upon to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the functions described in 10 CFR 54.4(a)(1).

During the scoping and screening methodology audit, the applicant stated that it evaluated the types of events listed in NEI 95-10 (i.e., anticipated operational occurrences, design basis accidents (DBAs), external events and natural phenomena) that were applicable to GGNS. The staff reviewed the applicant's basis documents that described design basis conditions in the CLB and addressed events defined by 10 CFR 50.49(b)(1) and 10 CFR 54.4(a)(1). The UFSAR and design basis documents discussed events such as internal and external flooding, tornados, and missiles. The staff determined that the applicant's evaluation of DBEs was consistent with SRP-LR.

The staff determined that the applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criterion in accordance with 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 report of the scoping results to confirm 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 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 SSW system 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 the sampled system consistent 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 determined 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 determined additional information would be required to complete its review. RAI 2.1-1, dated June 15, 2012, states, in part:

> During the on-site scoping and screening methodology audit, the staff reviewed the definitions of the term safety-related contained in fleet procedures, the UFSAR and the LRA, used to identify SSCs within the scope of license renewal. The staff determined that the applicability of 10 CFR 50.67 to GGNS was not specifically addressed in the definitions of the term safety related in the fleet procedures, the UFSAR or the LRA. The staff requested that the applicant

> confirm the definition of the term safety-related used in the development of the LRA and address the applicability of 10 CFR 50.67 to GGNS, as it relates to identifying SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)(iii). Perform a review of this issue and indicate if the review concludes that use of the scoping methodology precluded the identification of SSCs that should have included within the scope of license renewal in accordance with 10 CFR 54.4(a).

The applicant responded to RAI 2.1-1, by letter dated July 12, 2012, which states, in part

> The guideline exposures of 10 CFR 50.67 apply to GGNS based on license amendment 145. Components are classified as safety-related if they are relied upon to remain functional during and following design basis events to assure the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the applicable guideline exposures set forth in 10 CFR 50.67. Consequently, these components are included in the scope of license renewal. Use of the scoping method 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 the applicant had confirmed the definition of the term safety-related used in the development of the LRA and had addressed the applicability of 10 CFR 50.67 to GGNS, as it relates to identifying SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)(iii). The staff determined that 10 CFR 50.67 was applicable to GGNS and that it had been appropriately considered during the identification of safety-related SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). RAI 2.1-1 is resolved.

The staff determined additional information would be required to complete its review. RAI 2.1-2, dated June 15, 2012, states, in part:

> During the onsite scoping and screening methodology audit, the staff determined that certain SSCs identified as safety-related in the plant equipment database were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). In addition, the staff requested the applicant to provide the bases for not including any SSCs, identified as safety-related in the plant equipment database, within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). Perform a review of this issue and indicate if the review concludes that use of the scoping methodology precluded the identification of SSCs that should have been included within the scope of license renewal in accordance with 10 CFR 54.4(a).

The applicant responded to RAI 2.1-2, by letter dated July 12, 2012, which states, in part:

> Mechanical components classified as safety-related in the plant equipment database, but not subject to an aging management review, were reevaluated to assure they are either short-lived or are passive components or are conservatively classified as safety-related based on management decision even though they don't perform a safety function. With the exception of two components, the review confirmed that mechanical components classified as safety-related in the equipment database that are not subject to aging

management review are either short-lived or active components, or are conservatively classified as safety-related based on management decision.

> Two isokinetic probes in the standby gas treatment system discharge stack are classified as safety-related based on their support of the stack pressure boundary. These probes have been determined to be subject to aging management review as part of the standby gas treatment system.

The staff reviewed the response to RAI 2.1-2 and determined that the applicant had confirmed, with the exception of two isokinetic probes, that all SSCs identified as safety-related in the plant equipment data base, and having a 10 CFR 54.4(a)(1) intended function, were included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff further determined that, during review of the RAI, the applicant had identified two isokinetic probes that were within the scope of license renewal and required an AMR to be performed. RAI 2.1-2 is resolved.

2.1.4.1.3 Conclusion

Based on its review of the LRA and the applicant's implementing procedures and scoping results report, review of a system on a sampling basis, discussions with the applicant, and the applicant's responses to RAIs 2.1-1 and 2.1-2, 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) in LRA Section 2.1.1.2, "Application of Criterion for Nonsafety-Related SSCs Whose Failure Could Prevent the Accomplishment of Safety Functions," which states in part:

> This review identified nonsafety-related systems and structures containing components whose failure could prevent satisfactory accomplishment of a safety function. The method used was consistent with the preventive option described in Appendix F of NEI 95-10. Consideration of hypothetical failures that could result from system interdependencies that are not part of the current licensing basis and that have not been previously experienced is not required.

LRA Section 2.1.1.2.1, "Functional Failures of Nonsafety-Related SSCs," states, in part:

> At GGNS, systems and structures required to perform a function to support a safety function are generally classified as safety-related and have been included in the scope of license renewal per Section 2.1. For the exceptions where nonsafety-related equipment is required to remain functional to support a safety function (e.g., systems with components in closed systems supporting the secondary containment pressure boundary), the system containing the equipment has been included in scope, and the function is listed as an intended function for 10 CFR 54.4(a)(2) for the system.

LRA Section 2.1.1.2.2, “Physical Failures of Nonsafety-Related SSCs,” which states, in part:

> Some nonsafety-related components could affect safety-related components due to their physical proximity; that is, their physical location can result in interaction between the components should the nonsafety-related component fail. Based on the license renewal rule and the guidance in NEI 95-10, physical failures of nonsafety-related SSCs in scope based on 10 CFR 54.4(a)(2) fit into the following two categories.
>
> *(1) Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs*
>
> For nonsafety-related SSCs directly connected to safety-related SSCs (typically piping systems), the connected piping and supports up to and including the first seismic or equivalent anchor beyond the safety-nonsafety interface are within the scope of license renewal.
>
> *(2) Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs*
>
> Spatial interactions can occur as (1) physical impact or flooding, (2) pipe whip, jet impingement, or harsh environments (such as caused by a high-energy line break (HELB)), or (3) spray or leakage.

2.1.4.2.2 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(2), the applicant must consider all nonsafety-related SSCs whose failure could prevent the satisfactory accomplishment of safety-related functions, for SSCs relied on to remain functional during and following a DBE to ensure (1) the integrity of the RCPB, (2) the ability to shut down the reactor and maintain it in a safe shutdown condition, or (3) 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.

RG 1.188, Revision 1, endorses the use of NEI 95-10, Revision 6. NEI 95-10 discusses the staff’s position on 10 CFR 54.4(a)(2) scoping criteria, including nonsafety-related SSCs typically identified in the CLB; consideration of missiles, cranes, flooding, and HELBs; nonsafety-related SSCs connected to safety-related SSCs; nonsafety-related SSCs in proximity to safety-related SSCs; and mitigative and preventive options related to nonsafety-related and safety-related SSCs interactions.

In addition, the staff’s position (as discussed in NEI 95-10, Revision 6) is that applicants should not consider hypothetical failures but rather should base their 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 industry-wide 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 2.1.1.2, and subsections, in which the applicant described the scoping methodology for nonsafety-related SSCs in accordance with the requirements of 10 CFR 54.4(a)(2). In addition, the staff reviewed the applicant’s implementing document and results report, which documented the guidance and corresponding results of the applicant’s scoping review in accordance with the requirements of 10 CFR 54.4(a)(2). The applicant stated that it performed the review in accordance with the guidance contained in NEI 95-10, Revision 6, Appendix F.

Nonsafety-Related SSCs Required to Perform a Function that Supports a Safety-Related SSC. The staff determined that nonsafety-related SSCs required to remain functional to support a safety-related function had been reviewed by the applicant for inclusion within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff reviewed the evaluating criteria discussed in LRA Section 2.1.1.2, and subsections, and the applicant's 10 CFR 54.4(a)(2) implementing procedure. The staff determined that the applicant had reviewed the UFSAR, plant drawings, plant equipment database, 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 applicant also considered missiles, overhead handling systems, internal and external flooding, and HELBs. Accordingly, the staff finds that the applicant implemented an acceptable method for including nonsafety-related systems that perform functions that support safety-related intended functions, within the scope of license renewal as required by 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs. The staff determined that nonsafety-related SSCs, directly connected to SSCs, had been reviewed by the applicant for inclusion within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff reviewed the evaluating criteria discussed in LRA Section 2.1.1.2 and subsections, and the applicant's 10 CFR 54.4(a)(2) implementing procedure. The applicant had reviewed the safety-related to nonsafety-related interfaces for each mechanical system in order to identify the nonsafety-related components located between the safety to nonsafety-related interface and license renewal structural boundary.

The staff determined that in order to identify the nonsafety-related SSCs connected to safety-related SSCs and required to be structurally sound to maintain the integrity of the safety-related SSCs, the applicant 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, 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 2.1.1.2, and subsections, 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 had evaluated it and determined that the failure of the 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 that are attached to safety-related SSCs and required for structural support.

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).

The staff determined additional information would be required to complete its review. RAI 2.1-3, dated June 15, 2012, states, in part:

> During the on-site scoping and screening methodology audit the staff reviewed the license renewal application, the 10 CFR 54.4(a)(2) implementing documents and license renewal drawings, and also performed plant walkdowns. The staff determined through the audit activities and discussion with the applicant that equipment that was no longer required had been abandoned in place. They requested that the applicant provide details on the activities performed to confirm that all abandoned equipment, that at any time contained fluids and is in the proximity of safety-related SSCs, has been verified to be drained or included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). If abandoned equipment has not been verified to be drained and is not included within the scope of license renewal, provide a technical basis for not including the abandoned equipment within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Perform a review of this issue and indicate if the review concludes that use of the scoping methodology precluded the identification of SSCs that should have been included within the scope of license renewal in accordance with 10 CFR 54.4(a).

The applicant responded to RAI 2.1-3, by letter dated July 12, 2012, which states, in part:

> The only components for which credit for being abandoned was taken in the GGNS LRA were components in the auxiliary steam system. As stated in LRA Section 2.3.3.19, the auxiliary steam system contains components which have been abandoned, isolated, and drained. These details were determined through review of documents including piping and instrumentation diagrams, a design change package, a system operating instruction, and through discussions with site personnel.
>
> Any abandoned equipment, located in a space with safety-related equipment, that was not verified to be drained was included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

> A review of this issue indicated that use of this scoping method did not preclude the identification of systems and components within the scope of license renewal in accordance with 10 CFR 54.4(a). For instance, UFSAR Section 9.4.1.1.1 states that humidifiers in the control room HVAC system were abandoned in place. However, these humidifiers were subject to AMR, as identified in LRA Tables 2.3.3-17 and 3.3.2-17. Thus, no credit was taken in the GGNS LRA for these components being abandoned.

The staff reviewed the response to RAI 2.1-3 and determined that the applicant had performed a review and confirmed that all abandoned equipment had been isolated and confirmed drained or included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). RAI 2.1-3 is resolved.

2.1.4.2.3 Conclusion

Based on its review of the LRA and the applicant's implementing procedures and scoping results report, selected system reviews and walkdowns, discussions with the applicant, and the applicant’s response to RAI 2.1-3, 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 2.1.1.3, “Application of Criterion for Regulated Events,” states in part:

> The scope of license renewal includes those systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61) [not applicable to GGNS, a BWR], anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63). Systems and structures in the scope of license renewal for fire protection include those required for compliance with 10 CFR 50.48. Equipment relied on for fire protection includes SSCs credited with fire prevention, detection, and mitigation in areas containing equipment important to safe operation of the plant as well as systems that contain plant components credited for safe shutdown following a fire.

2.1.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.1.1.3, which described the methods 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 (10 CFR 50.48), environmental qualification (EQ) (10 CFR 50.49), anticipated transients without scram (ATWS) (10 CFR 50.62), and station blackout (SBO) (10 CFR 50.60).

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 the scoping results report. The staff determined that the applicant had evaluated the CLB to identify SSCs that perform functions addressed in 10 CFR 54.4(a)(3), "Regulated Events," and included these SSCs within the scope of license renewal as documented in the scoping report. In addition, the staff determined that the scoping report 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 documents 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 applicable Fire Protection technical basis documents. 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 results for the systems and structures identified in the applicable Fire Protection technical basis documents.

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 fire protection functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

Environmental Qualification. The staff reviewed the applicant's implementing procedure that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (Environmental Qualification—10 CFR 50.49). The implementing procedure described a process that considered CLB information and used a bounding approach that included all plant electric and instrumentation and control (I&C) SSCs within the scope of license renewal. 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. Based on its review of the CLB documents and a sample of scoping results documentation, 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. The staff reviewed the applicant's implementing procedure that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (Anticipated Transients Without Scram—10 CFR 50.62). The implementing procedure described a process that considered CLB information and used a bounding approach that included all plant electric and I&C SSCs within the scope of license renewal. The staff reviewed the 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. Based on its review of the CLB documents and a sample of scoping results documentation, 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. The staff reviewed the applicant's implementing procedure that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (Station Blackout—10 CFR 50.63). The implementing procedure described a process that considered CLB information and used a bounding approach that included all plant electrical and I&C SSCs within the scope of license renewal. 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. Based on its review of the CLB documents and a sample of scoping results documentation, 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).

2.1.4.3.3 Conclusion

Based on its review of the LRA and the applicant's implementing procedures and scoping results report, 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

LRA Section 2.1.1, "Scoping Methodology" states, in part:

> For mechanical system scoping, a system is defined as the collection of components in the equipment database assigned to the system code. System functions are determined based on the functions performed by those components. Defining a system by the components in the database is consistent with the evaluations performed for maintenance rule scoping by the site.
>
> Intended functions for structures and mechanical systems were identified based on reviews of applicable plant licensing and design documentation. Documents reviewed included the UFSAR, Technical Specifications, the Fire Hazards Analysis (Appendix 9A of the UFSAR), the Appendix R Safe Shutdown Analysis, Maintenance Rule basis documents, design basis documents, and various station drawings as necessary.

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 that are 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 report. The process defined the plant in terms of systems and structures and was completed for all systems and structures on site 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 a report in accordance with the implementing procedures. The report 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 scoping and screen methodology audit, the staff reviewed a sampling of the implementing procedure and report 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, site guidance documents, and a sampling of system and structure scoping results reviewed during the scoping and screening methodology audit, the staff concludes that the applicant's methodology for identifying SSCs within the scope of license renewal, and their intended functions, is consistent with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.5 Mechanical Component Scoping

2.1.4.5.1 Summary of Technical Information in the Application

LRA Section 2.1.1, "Scoping Methodology" states, in part:

> For mechanical system scoping, a system is defined as the collection of components in the equipment database assigned to the system code. System functions are determined based on the functions performed by those components. Defining a system by the components in the database is consistent with the evaluations performed for maintenance rule scoping by the site.
>
> Intended functions for structures and mechanical systems were identified based on reviews of applicable plant licensing and design documentation. Documents reviewed included the UFSAR, Technical Specifications, the Fire Hazards Analysis (Appendix 9A of the UFSAR), the Appendix R Safe Shutdown Analysis, Maintenance Rule basis documents, design basis documents, and various station drawings as necessary.

2.1.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.1.1, implementing procedures, scoping results report, 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 adequate 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 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 Section 2.1.1 and the guidance contained in the SRP-LR.

On a sampling basis, the staff reviewed the applicant's scoping report for the SSW 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 reviewed 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 components subject to aging management review 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 determined that the applicant's license renewal personnel verifying the results had performed independent reviews of the scoping report and the applicable license renewal drawings to ensure accurate identification of the system intended functions. The staff determined 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 SCs were included within the scope of license renewal in accordance with 10 CFR 54.4(a).

2.1.4.5.3 Conclusion

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

2.1.4.6 Structural Component Scoping

2.1.4.6.1 Summary of Technical Information in the Application

LRA Section 2.1.1, "Scoping Methodology" states, in part:

> Structural components included in system codes with mechanical equipment, such as snubbers, and structural commodities associated with mechanical systems, such as pipe hangers and insulation, are evaluated as structural components and bulk commodities.
>
> As the starting point for structural scoping, a list of plant structures was developed from a review of the UFSAR, plant layout drawings, Fire Hazards Analysis, design criteria documents, and maintenance rule basis documents. The list includes structures that potentially support plant operations or could adversely impact structures that support plant operations (i.e., seismic II/I). In addition to buildings and facilities, the list of structures includes other structures that support plant operation (e.g., electrical manholes and foundations for freestanding tanks).

2.1.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.1.1, implementing procedures, scoping results report, 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 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 Section 2.1.1 and the guidance contained in the SRP-LR, Section 2.1.

On a sampling basis, the staff reviewed the applicant's scoping report 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 reviewed 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 determined that the applicant's license renewal personnel verifying the results had performed independent reviews of the scoping report and the applicable license renewal drawings to ensure accurate identification of the system intended functions. The staff determined that the SCs the applicant identified 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 SCs were included within the scope of license renewal in accordance with 10 CFR 54.4(a).

The staff determined additional information would be required to complete its review. RAI 2.1-4, dated June 15, 2012, states, in part:

> During the on-site scoping and screening methodology audit the staff reviewed the license renewal application, license renewal implementing documents, current licensing basis documentation and performed walkdowns of the incomplete and abandoned Unit 2 turbine building and other adjacent structures.
>
> The staff determined that the Unit 2 turbine building, which is adjacent to the GGNS turbine building and control building, both of which are within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), is not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). In addition, the staff noted that the radioactive waste building, which is also adjacent to the GGNS turbine building (but not the control building), is included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for an intended function that includes, "Maintain structural integrity of nonsafety-related components such that safety functions are not affected and no impact on in-scope structures."
>
> During the scoping and screen methodology audit the applicant indicated that the basis for not including the incomplete and abandoned Unit 2 turbine building within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) was an analysis that demonstrated that the Unit 2 turbine building would not move in a way that impacts adjacent buildings following flooding and earthquake events. However, the applicant did not provide information that demonstrated that the Unit 2 turbine building would not be subject to the effects of aging similar to other buildings of the same construction that the applicant had included within the scope of license renewal and made subject to an aging management program.
>
> The staff requested that the applicant provide a technical basis for not including the incomplete and abandoned Unit 2 turbine building, located adjacent to the GGNS turbine building and the control building, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). If an analysis is cited as the

technical basis for not including the Unit 2 turbine building within the scope of license renewal, demonstrate how the analysis considers the effects of aging relative to other buildings of similar construction that are included within the scope of license renewal. Perform a review of this issue and indicate if the review concludes that use of the scoping methodology precluded the identification of SSCs that should have been included within the scope of license renewal in accordance with 10 CFR 54.4(a).

The applicant responded to RAI 2.1-4, by letter dated July 12, 2012, which states, in part:

> The Grand Gulf Nuclear Station (GGNS) Unit 2 turbine building is a non-Category I structure located adjacent to the GGNS Unit 1 turbine building and the control building. The Unit 2 turbine building is constructed of reinforced concrete and structural steel with metal roof decking and metal siding. The interior walls are constructed of reinforced concrete or concrete masonry block. The structure consists of steel superstructure with an exterior metal siding above the operating floor at El. 166'-0" and reinforced concrete below El. 166'-0". The Unit 2 turbine building is designed to comply with seismic Category I requirements and tornado effects (except the siding and its supporting members) and thus will have no effect on the adjacent Category I structures. As indicated in the LRA Table 2.2-4, construction of the Unit 2 turbine building has been abandoned; however the partially completed building still remains. An analysis was performed of the partially completed Unit 2 turbine building configuration to evaluate any potential effect on surrounding structures. The analysis demonstrated that the Unit 2 turbine building will not move in a way that would impact adjacent buildings following flooding and earthquake events. The analysis was the technical basis for not including the abandoned and partially completed Unit 2 turbine building within the scope of license renewal. However, to ensure that the effects of aging do not affect its structural integrity as analyzed (i.e., it was analyzed to withstand design basis events to preclude adverse impact on adjacent category I structures), the Unit 2 turbine building is being included within the scope of license renewal for 10 CFR 54.4(a)(2) and subject to an AMR. Since the Unit 2 turbine building does not provide structural support or house any system, structure, or component (SSC) performing a license renewal intended function, only the Unit 2 turbine building steel superstructure framing and main concrete structural elements are subject to an AMR.
>
> A review was performed of the GGNS scoping method as described in LRA Section 2.1.1. During the review, Entergy determined that the Unit 2 auxiliary building was in a condition similar to that of the Unit 2 turbine building. To ensure that the effects of aging do not affect its structural integrity, during the period of extended operation (PEO), the partially completed Unit 2 auxiliary building is also being included within the scope of license renewal for 10 CFR 54.4(a)(2) and subject to an AMR. The GGNS Structures Monitoring Program will be enhanced to include managing the effects of aging on the GGNS Unit 2 turbine building and the GGNS Unit 2 auxiliary building during the PEO.

The staff reviewed the response to RAI 2.1-4 and determined that the applicant had performed a review and made a determination to include the abandoned Unit 2 turbine building and Unit 2 auxiliary building within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) and that the buildings were subject to an AMR. RAI 2.1-4 is resolved.

2.1.4.6.3 Conclusion

Based on its review of the LRA, scoping implementation procedures, and a sampling review of structural scoping results, and the applicant's response to RAI 2.1-4, 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, is acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

LRA Section 2.1.1, "Scoping Methodology" states, in part:

> For the purposes of system level scoping, plant EIC systems are included in the scope of license renewal by default. EIC components in mechanical systems are included in the evaluation of EIC components, regardless of whether the mechanical system is included in scope. Intended functions for EIC systems are not identified since the bounding (i.e., included by default) scoping approach makes it unnecessary to determine if an EIC system has an intended function. Switchyard equipment, which is not part of the plant's EIC systems, was reviewed for station blackout (SBO) intended functions based on NRC guidance in NUREG-1800, Section 2.5.2.1.1.

2.1.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.1 and the guidance contained in the implementing procedures and scoping results report to perform the review of the electrical scoping process. The staff reviewed the applicant's approach to identifying electrical and instrumentation and control SSCs relied upon to perform the functions described in 10 CFR 54.4(a). The staff reviewed portions of the documentation the applicant used to perform the electrical scoping process, including license renewal procedures, basis documents, scoping and screening report, the UFSAR, CLB documentation, and NEI 95-10.

The staff noted that after the scoping of electrical and instrumentation and controls (I&C) components was performed, the in-scope electrical components 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, such as cable, connections, fuse holders, terminal blocks, high-voltage transmission conductor, connections and insulators, switchyard bus and connections.

As part of this review, the staff discussed the methodology with the applicant, reviewed the implementing procedures developed to support the review, and reviewed the scoping results for a sample of SSCs that were identified within the scope of license renewal. 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.

2.1.4.7.3 Conclusion

Based on its review of 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, is 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 is consistent with the guidance contained in the SRP-LR and identified those SSCs (1) that are safety related, (2) whose failure could affect safety-related functions, and (3) that are necessary to demonstrate compliance with the NRC's regulations for fire protection, EQ, ATWS, and SBO. The staff concludes 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 2.1.2, "Screening Methodology" states, in part:

> NEI 95-10 provides industry guidance for screening structures and components to identify the passive, long-lived structures and components that support an intended function. The screening process for GGNS followed the recommendations of NEI 95-10.
>
> Within the group of systems and structures that are in scope, passive long-lived components or structural elements that perform intended functions require aging management review. Components or structural elements that support an intended function do not require aging management review if they are either active or subject to replacement based on a qualified life.
>
> Although the requirements for the integrated plant assessment are the same for each system and structure, in practice the screening process differed for mechanical systems, electrical systems, and structures.

2.1.5.1.2 Staff Evaluation

Pursuant to 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 report for the SSW 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 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 in-scope of license renewal that are subject to an AMR. The staff concludes that the applicant's process for determining the SCs that are subject to an AMR is consistent with the requirements of 10 CFR 54.21 and, therefore, is 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 discussed in LRA Sections 2.1.2.1, "Screening of Mechanical Systems," and 2.1.2.1.1, "Identifying Components Subject to Aging Management Review."

LRA Section 2.1.2.1.1 "Identifying Components Subject to Aging Management Review," states, in part:

> Within the system, components are subject to aging management review if they perform an intended function without moving parts or a change in configuration or properties and if they are not subject to replacement based on a qualified life or specified time period.
>
> In making the determination that a component performs an intended function without moving parts or a change in configuration or properties, it is not necessary to consider the piece parts of the component. However, in the case of valves, pumps, and housings for fans and dampers, the valve bodies, pump casings, and housings may perform an intended function by maintaining the pressure boundary and may therefore be subject to aging management review.

> Replacement programs are based on vendor recommendations, plant experience, or any means that establishes a specific service life, qualified life, or replacement frequency under a controlled program. Components that are subject to replacement based on qualified life or specified time period are not subject to aging management review. Where flexible elastomer hoses/expansion joints or other components are periodically replaced, these components are not subject to aging management review.

2.1.5.2.2 Staff Evaluation

The staff reviewed the applicant's methodology used for mechanical component screening as described in LRA Sections 2.1.2.1 and 2.1.2.1.1, implementing procedures, basis documents, and the mechanical scoping and screening report. The staff determined 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 were found to meet 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 SSW 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 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, is 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 2.1.2.2 "Screening of Structures," states, in part:

> For each structure within the scope of license renewal, the structural components and commodities were evaluated to determine those subject to aging management review. This evaluation (screening process) for structural components and commodities involved a review of design basis documents (UFSAR, design criteria documents, design specifications, site drawings, etc.) to identify specific structural components and commodities that make up the structure. Structural components and commodities subject to aging management review are those that (1) perform an intended function without moving parts or a

> change in configuration or properties, and (2) are not subject to replacement based on qualified life or specified time period.

2.1.5.3.2 Staff Evaluation

The staff reviewed the applicant's methodology used for structural component screening as described in LRA Section 2.1.2.2, implementing procedures, basis documents, and the structural scoping and screening report. The staff determined 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 which were found to meet 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 not subject to replacement based on a qualified life or specified time period (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 the LRA, implementing procedures, and the sampled structural screening results, the staff concludes that the applicant's methodology for identification of structural components 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, is acceptable.

2.1.5.4 Electrical Component Screening

2.1.5.4.1 Summary of Technical Information in the Application

LRA Section 2.1.2.3 "Electrical and Instrumentation and Control Systems," states, in part:

> The EIC aging management review evaluates commodity groups containing components with similar characteristics. Screening applied to commodity groups determines which EIC components are subject to aging management review. An aging management review is required for commodity groups that perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties (passive) and that are not subject to replacement based on a qualified life or specified time period (long-lived).

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant's methodology used for electrical component screening in LRA Section 2.1.2.3 and the applicant's implementing procedures, basis documents, and the electrical scoping and screening report. The staff determined 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 electrical and instrumentation and control (EIC) components subject to an AMR.

The staff determined that the applicant had identified commodity groups that were found to meet the passive criteria in accordance with NEI 95-10. In addition, the staff determined that the applicant evaluated the identified passive commodities to identify whether they were subject to replacement based on a qualified life or specified time period (short lived), or not subject to replacement based on a qualified life or specified time period (long lived) and that the remaining passive, long-lived components were determined to be subject to an AMR.

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 for identification of electrical components 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, is acceptable.

2.1.5.5 Conclusion for Screening Methodology

Based on its review of the LRA and the screening implementing procedures, discussions with the applicant, and a sample review of screening results, the staff determines that the applicant's screening methodology is consistent with the guidance contained in the SRP-LR and identified those passive, long-lived components within the scope of license renewal and 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 scoping results report, the information presented during the scoping and screening methodology audit, discussions with the applicant sample system reviews, and the applicant's responses dated July 12, 2012, to the staff's RAIs, 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 Tables 2.2-1 and 2.2-3, the applicant listed plant mechanical systems, structures, and electrical and I&C systems that are 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 safety evaluation report (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-A, "Mechanical Systems within the Scope of License Renewal"; Table 2.2-1-B, "Plant EIC Systems within the Scope of License Renewal"; Table 2.2-2, "Mechanical Systems Not within the Scope of License Renewal"; Table 2.2-3, "Structures within the Scope of License Renewal"; and Table 2.2-4, "Structures Not within the Scope of License Renewal," to confirm that there were no omissions of plant-level systems and structures within the scope of license renewal.

The staff determined whether the applicant properly identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4. The staff reviewed selected systems and structures that the applicant did not identify as within the scope of license renewal to verify whether 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 May 9, 2012, the staff noted LRA Section 2.2, Tables 2.2-1-A, 2.2-1-B, 2.2-2, 2.2-3, and 2.2-4 provide the results of applying the license renewal scoping criteria to the systems, structures, and components.

The license renewal scoping criteria is described in Section 2.1. The following UFSAR systems did not appear in LRA Tables 2.2-1-A, 2.2-1-B, 2.2-2, 2.2-3 or 2.2-4.

UFSAR Section	System
7.5.1.2.18. Post-Accident Sampling	Post-accident sampling system
18.1.7. Plant Safety Parameter Display 18.2.2 Safety Parameter Display System	Safety-related display instrumentation system
11.3 Gaseous Radwaste System	Gaseous waste management systems
7.6.2.11 Auxiliary Building Isolation System	Auxiliary Building Isolation System

The applicant was requested to justify its exclusion of the above systems from Tables 2.2-1-A, 2.2-1-B, 2.2-2, 2.2-3, or 2.2-4.

In its response, by letter dated June 5, 2012, the applicant stated the UFSAR identifies these systems using system names that explain their function within the plant. The post-accident sampling system is a subsystem of the process sampling system and is described in LRA Section 2.3.3.19. The safety parameter display system uses components of the emergency response facilities and is identified in LRA Table 2.2-1-B. Gaseous radwaste management is accomplished with various plant systems. These include vent systems of normally and potentially radioactive components, building ventilation systems, the offgas system, and the mechanical vacuum pump system. Building ventilation systems are described in LRA Section 2.3.3.18. The primary gaseous radwaste management system is the main condenser steam jet air ejector low-temperature system, or offgas system. The low-temperature offgas system is described in LRA Section 2.3.4.2. The auxiliary building isolation system is a subsystem of the containment and drywell I&C system. The containment and drywell I&C system is described in LRA Section 2.3.2.7.

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, which are within systems that are included in Tables 2.2-1-A, 2.2-1-B, 2.2-2, 2.2-3, or 2.2-4. 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 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 in accordance with 10 CFR 54.4 the systems and structures within the scope of license renewal.

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 coolant system (RCS)
- engineered safety features (ESF)
- 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 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 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 (1) the functions are performed with moving parts or a change in configuration or properties or (2) 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 Coolant System

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

- 2.3.1.1, "Reactor System"
- 2.3.1.2, "Reactor Coolant Pressure Boundary"
- 2.3.1.3, "Nuclear Boiler System"
- 2.3.1.4, "Reactor Recirculation System"
- 2.3.1.5, "Neutron Monitoring"
- 2.3.1.6, "Fuel"
- 2.3.1.7, "Miscellaneous RCS Systems in Scope for 10 CFR 54.4(a)(2)"

The staff's findings on review of LRA Sections 2.3.1.1–2.3.1.7 are provided in SER Sections 2.3.1.1–2.3.1.7, respectively.

2.3.1.1 Reactor System

2.3.1.1.1 Summary of Technical Information in the Application

The reactor system consists of the RV and its attachments and RVI. The reactor pressure vessel (RPV) is a vertical, cylindrical pressure vessel of welded construction designed by 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 flanges are sealed by two concentric rings designed to prevent leakage through the inner or outer seal at any operating condition.

The RVI components include the core (including fuel assemblies, control rod assemblies, control rod guide thermal sleeves, guide rods, in-core dry tubes, and in-core guide tubes), core support structure (control rod guide tubes, core plate and holddown bolts, fuel supports, shroud, shroud support, and top guide), core spray (CS) lines and spargers, differential pressure line, feedwater (FW) spargers, jet pump assemblies and instrumentation, low-pressure coolant injection couplings, steam dryer, shroud head and steam separator assembly, and surveillance sample holders.

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

- maintain the RCPB
- provide a barrier to radiation release
- 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 (ECCSs) can perform their safety functions
- provide active nuclear fuel and cladding
- provide emergency reactor shutdown capability

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), thermal sleeves, in-core penetrations (housings), internal attachments (including shroud support, jet pump riser support pads, CS brackets, steam dryer holddown brackets, guide rod brackets, surveillance specimen brackets, steam dryer support brackets, and FW sparger brackets), stabilizer brackets, support skirt and bearing plate, the control rod drive (CRD) stub tubes and housings, and associated pressure boundary bolting.

The RVI evaluation boundary includes the core support subcomponents and other RVI components. There are no boundary drawings for the RV or the RVI. Additional details for components subject to an AMR can be found in UFSAR Sections 3.9.5, 4.1, 4.1.2, 4.1.3, 4.6, 5.3.1, and 5.3.3. LRA Table 2.3.1-1 lists the RV components that require AMR and their intended functions. LRA Table 2.3.1-2 lists the RVI components that require AMR and their intended functions.

2.3.1.1.2 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).

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 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).

2.3.1.2 Reactor Coolant Pressure Boundary

2.3.1.2.1 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 (Section 2.3.1.4) and the nuclear boiler system (Section 2.3.1.3) comprise a majority of the RCPB. A list of systems that contain RCPB components can be found in LRA Table 2.3.1.2-A.

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

- maintain integrity of the RCPB
- provide isolation and integrity of primary containment
- provide capability to trip recirculation pumps

Additional details for RCPB components subject to an AMR can be found in UFSAR Section 5.1. UFSAR references for individual systems that make up the RCPB can be found in their respective sections.

The following highlighted license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

LRA-M-1081B	LRA-M-1077A	LRA-M-1077B	LRA-M-1077D
LRA-M-1077E	LRA-M-1078A	LRA-M-1078B	LRA-M-1078E
LRA-M-1082	LRA-M-1085A	LRA-M-1085B	LRA-M-1085C
LRA-M-1087	LRA-M-1086	LRA-M-1090A	LRA-M-1097
LRA-M-1112	LRA-M-1083B	LRA-M-1079	

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

2.3.1.2.2 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).

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 RCPB 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 Nuclear Boiler System

2.3.1.3.1 Summary of Technical Information in the Application

The nuclear boiler system is comprised of the main steam and FW lines and the nuclear pressure relief system and automatic depressurization system components. The nuclear boiler system transports steam from the RPV to the turbine. Each of the four main steam lines contains two air operated main steam isolation valves (MSIVs) to protect against the post-accident release of radiation. Between the RPV and the MSIVs are safety/relief valves that protect the RCS from overpressure. Additionally, each main steam line contains a flow restrictor assembly to limit the blowdown rate. The automatic depressurization system allows the low pressure ECCS to inject water to the RPV in the event of a small break loss-of-coolant accident (LOCA) by rapidly decreasing the pressure in the RPV.

Additional details for components subject to an AMR can be found in UFSAR Sections 5.2.2.4.1, 5.4.4, 5.4.5, 5.4.9, 6.3.1.2.4, 6.3.2.2.2, and 7.3.1.1.2.4.1.12.

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

- maintain RCPB integrity
- provide primary containment isolation and integrity
- reduce RPV pressure to allow low pressure ECCS to inject when needed
- limit the blowdown rate
- provide steam to the reactor core isolation cooling (RCIC) turbine

The following highlighted license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

LRA-M-1077A	LRA-M-1077B	LRA-M-1077D	LRA-M-1077E
LRA-M-1124A	LRA-M-1067A	LRA-M-1068A	LRA-M-1124B
LRA-M-1067D	LRA-M-1068C	LRA-M-1077C	LRA-M-1124C
LRA-M-1067E	LRA-M-1101	LRA-M-1067M	

LRA Tables 2.3.1-3 and 2.3.1-4-1list the component types that require AMR and their intended functions.

2.3.1.3.2 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).

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 nuclear boiler 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).

2.3.1.4 Reactor Recirculation System

2.3.1.4.1 Summary of Technical Information in the Application

The reactor recirculation system provides coolant flow through the core. The reactor recirculation system consists of the two recirculation pump loops external to the RV. Each external loop contains one motor-driven recirculation pump, a hydraulically-actuated flow control valve, two motor-operated gate valves, a flow measuring system, and provides the piping path to the RV jet pumps.

Additional details for components subject to an AMR can be found in UFSAR Section 5.1, Section 5.4.1, and Table 9.5-12.

The intended functions of reactor recirculation system component types within the scope of license renewal includes:

- serves as a pressure boundary and limits the release of fission products
- provides a containment isolation function

The following highlighted license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR.

LRA-M-1078A	LRA-M-1078B	LRA-M-1078C	LRA-M-1078D
LRA-M-1078E	LRA-M-0033B	LRA-M-1079	LRA-M-1089
LRA-M-0034B	LRA-M-1080B	LRA-M-1099	LRA-M-1069D
LRA-M-1083B	LRA-M-1110A	LRA-M-1072B	LRA-M-1085A
LRA-M-1111A	LRA-M-1088C	LRA-M-1088E	

LRA Tables 2.3.1-3 and 2.3.1-4-2 list the component types that require AMR and their intended functions.

2.3.1.4.2 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).

2.3.1.4.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the reactor recirculation 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).

2.3.1.5 Neutron Monitoring

2.3.1.5.1 Summary of Technical Information in the Application

The purpose of the neutron monitoring system is to provide indication of neutron flux that can be correlated to thermal power level. The system includes in-core neutron detectors and out-of-core electronic monitoring equipment. The five major subsystems are: source range monitor (SRM) subsystem, intermediate range monitor (IRM) subsystem, local power range monitor (LPRM) subsystem, traversing incore probe (TIP) subsystem, and average power range monitor (APRM) subsystem. The SRM and IRM detectors and cable are located inside the RV in a dry tube sealed against RV pressure. The LPRM assembly consists of four neutron detectors contained in a multiple dry tube assembly. Each LPRM assembly also contains a calibration tube for a TIP. The TIP subsystem provides a way to calibrate the individual LPRM sensors by correlating TIP signals to LPRM signals as the TIP is positioned in various radial and axial locations in the core through a drive mechanism. A TIP drive mechanism uses a fission chamber attached to a flexible drive cable. The cable is driven from outside the drywell by a gearbox assembly. The APRM channel uses electronic equipment that averages the output signals from a selected set of LPRMs.

Additional details for components subject to an AMR can be found in UFSAR Sections 7.1.2.1.4, 7.6.1.5, and 7.7.1.6.

The intended functions of the neutron monitoring system component types within the scope of license renewal include:

- maintain RCPB integrity

There are no license renewal drawings specific to the neutron monitoring system. LRA Tables 2.3.1-2 and 2.3.2-7 list the component types that require AMR and their intended functions.

2.3.1.5.2 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).

2.3.1.5.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the neutron monitoring 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).

2.3.1.6 Fuel

2.3.1.6.1 Summary of Technical Information in the Application

Fuel assembly subcomponents comprise the fuel system. Fuel assemblies provide active nuclear fuel, the ability to maintain the fuel in a controllable and coolable configuration, and fission product retention. Fuel assemblies are replaced regularly and are therefore in scope for license renewal, but not subject to an AMR.

Additional details for components of the fuel review can be found in UFSAR Section 4.2.

The intended functions of the fuel system component types within the scope of license renewal include:

- provide a barrier to radiation release
- provide structural integrity

There are no license renewal drawings for the fuel system.

2.3.1.6.2 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).

2.3.1.6.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the fuel 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).

2.3.1.7 Miscellaneous RCS Systems in Scope for 10 CFR 54.4(a)(2)

2.3.1.7.1 Summary of Technical Information in the Application

LRA Section 2.3.1.7 describes the purpose for including nonsafety-related SSCs within the scope of license renewal for both the nuclear boiler system (LRA Section 2.3.1.3) and the reactor recirculation system (LRA Section 2.3.1.4) based on the criterion in 10 CFR 54.4(a)(2) for physical interactions. References to the tables listing the component types that require AMR (Tables 2.3.1-4-1 and 2.3.1-4-2) and references to the license renewal drawings for both of these systems were included in this section.

2.3.1.7.2 Staff Evaluation

SER Sections 2.3.1.3 and 2.3.1.4 provide the staff evaluation for the individual systems.

2.3.1.7.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the miscellaneous RCS systems in scope for 10 CFR 54.4(a)(2) 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 engineered safety feature SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the ESF in the following LRA sections:

- 2.3.2.1, “Residual Heat Removal”
- 2.3.2.2, “Low Pressure Core Spray”
- 2.3.2.3, “High Pressure Core Spray”
- 2.3.2.4, “Reactor Core Isolation Cooling”
- 2.3.2.5, “Pressure Relief”
- 2.3.2.6, “Standby Gas Treatment”
- 2.3.2.7, “Containment Penetrations”
- 2.3.2.8, “Miscellaneous ESF Systems in Scope for 10 CFR 54.4(a)(2)”

The staff’s findings on review of LRA Sections 2.3.2.1–2.3.2.8 are in SER Sections 2.3.2.1–2.3.2.8, respectively.

2.3.2.1 Residual Heat Removal

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the residual heat removal (RHR) system and the drywell, suppression pool, and upper containment pool system. The LRA states that the purpose of the RHR system is to remove decay and sensible heat from the RV and the containment under normal operation, shutdown, refueling, and accident conditions. The RHR system removes decay and sensible heat during and after plant shutdown, injects water into the RV following a LOCA, and removes heat from the containment following a LOCA. The LRA states that the drywell, suppression pool, and upper containment pool includes the suppression pool ECCS/RCIC suction strainer, suction piping and expansion joints, and the air regulator valves for the gate seals in the upper containment pool. The suppression pool strainer and suction piping provide the safety-grade source of water to the ECCS and RCIC pumps.

The LRA states that the RHR system has the intended functions to restore and maintain water level in the RV for cooling after a LOCA, to provide an alternate shutdown cooling function to remove decay and sensible heat from the reactor core in the event the shutdown suction line from the reactor recirculation system is unavailable, to remove heat from the suppression pool following a DBA, to remove decay and sensible heat from the reactor core to cooldown and maintain the reactor in a cold shutdown condition, to assist the fuel pool cooling and cleanup system in removing decay heat from fuel assemblies stored in the fuel pools, to remove heat and condense steam from the drywell to prevent over-pressurization of the containment following a LOCA, to remove fission products dispersed in the containment atmosphere following a LOCA, to maintain integrity of the RCPB, and to support containment pressure boundary. The RHR system also has the intended functions to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function and to provide emergency makeup to the spent fuel pool. Additionally, the RHR system has an intended function to demonstrate compliance with the NRC's regulations for fire protection (10 CFR 50.48).

The LRA states that the drywell, suppression pool, and upper containment pool system has an intended function to provide the safety-grade source of water to the ECCS and RCIC pumps. The system also has an intended function to demonstrate compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.2-1 identifies the RHR 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 and UFSAR Sections 1.2.2.3.4, 5.4.7, 6.3.1.2.3, 6.3.2.2, 6.3.2.2.4, and 6.5.2, and LRA Tables 2.3.2-1 and 3.2.2-1, 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 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).

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 RHR 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 Low-Pressure Core Spray

2.3.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 describes the purpose of the LPCS. As part of the ECCS, it limits the release of radioactive materials to the environs following a LOCA. The system pumps water through a peripheral ring spray sparger mounted above the reactor core. The system also provides inventory makeup and spray cooling during large breaks when reactor pressures are relatively low. Additionally, the low-pressure core spray (LPCS) system provides inventory makeup for small breaks after the automatic depressurization system reduces the RV pressure.

The LRA states that the LPCS system's intended functions are to supply water spray to fuel bundles in the reactor core to prevent excessive fuel cladding temperatures in the event of a LOCA, to maintain integrity of the RCPB, and to support the containment pressure boundary. The system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.2-2 identifies the LPCS system component types that are 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 and UFSAR Sections 6.3.1.2 and 6.3.2.2, and LRA Tables 2.3.2-2 and 3.2.2-2, 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 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).

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 LPCS 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 Core Spray

2.3.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 describes the purpose of the high-pressure core spray (HPCS) system, which is part of the ECCS. The system limits the release of radioactive materials to the environs following a LOCA. The HPCS system pumps water through a peripheral ring spray sparger mounted above the reactor core. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level and depressurizes the vessel. For large breaks, the HPCS system cools the core by a spray.

The LRA states that the HPCS system has the intended functions to supply water spray to fuel bundles in the reactor core to prevent excessive fuel cladding temperatures in the event of a LOCA, to maintain integrity of the RCPB, and to support the containment pressure boundary. The system also has an intended function to maintain the integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.2-3 identifies the HPCS 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, UFSAR Sections 6.3.1.2 and 6.3.2.2, and LRA Tables 2.3.2-3 and 3.2.2-3, 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 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).

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 HPCS system components within the scope of license renewal, as required by 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

2.3.2.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the purpose of the RCIC system, which is to provide makeup water to the RV following a RV isolation accompanied by a loss of coolant flow from the FW system to provide adequate core cooling and control of the RV water level.

The LRA states that the RCIC system has the intended functions to provide makeup water to the RV following a RV isolation accompanied by a loss of coolant flow from the FW system to provide adequate core cooling and control of the RV water level, to maintain integrity of the RCPB, and to support the containment pressure boundary. The system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the reactor core isolation system has intended functions to demonstrate compliance with the NRC's regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63).

LRA Table 2.3.2-4 identifies the RCIC system component types that are 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, UFSAR Section 5.4.6.2.1 and Appendix 8A, and LRA Tables 2.3.2-4 and 3.2.2-4, 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 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).

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 Pressure Relief

2.3.2.5.1 Summary of Technical Information in the Application

LRA Section 2.3.2.5 describes the nuclear pressure relief, the automatic depressurization components, and the quencher confirmatory test program systems. The purpose of the automatic depressurization system is to rapidly reduce RV pressure in a small break LOCA situation in which the HPCS system fails to maintain the RV water level. The automatic depressurization system uses some of the relief valves that are part of the nuclear pressure relief system. The nuclear pressure relief system consists of safety/relief valves located on the main steam lines between the RV and the first isolation valve within the drywell. These valves protect against overpressure of the nuclear system. The quencher confirmatory test program system includes piping, valves, and instruments used in the one-time quencher confirmatory test. The objectives of the test were to confirm the validity of the methods used to predict the pressure fields within the containment suppression pool caused by safety/relief valve air clearing loads.

The LRA states that the pressure relief systems have the intended functions to prevent over-pressurization of the RCPB by use of a pressure relief system and to reduce RV pressure in a LOCA situation in which the HPCS system fails to maintain the RV water level. The pressure relief systems also have an intended function to demonstrate compliance with the NRC‘s regulations for fire protection (10 CFR 50.48). The quencher confirmatory test program system has the intended function to support the automatic depressurization system pressure boundary.

LRA Table 2.3.2-5 identifies the pressure relief 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 reviewed LRA Sections 2.3.2.5, and UFSAR Sections 1.2.2.4.8, 5.2.2, 5.2.2.4, 6.2.1.1.3.3.1.1, 6.3.1.2.4, 6.3.2.2.2, 7.3.1.1.1.4, and Appendix 6A: Section 3BA.7.2.2.3 and Appendix 6B (QCTP system code) and LRA Tables 2.3.2-5 and 3.2.2-5 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 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).

2.3.2.5.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the pressure relief 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).

2.3.2.6 Standby Gas Treatment

2.3.2.6.1 Summary of Technical Information in the Application

LRA Section 2.3.2.6 describes the purpose of the standby gas treatment system (SGTS), which is to minimize exfiltration of contaminated air from the enclosure building, the auxiliary building, and the containment following an accident or abnormal condition that could result in abnormally high airborne radioactivity in these areas.

The LRA states that the SGTS has the intended functions to provide recirculation, filtration, and exhaust of the secondary containment air to maintain a negative pressure in the secondary containment volume and limit release of radioisotopes to the environment under accident conditions and to support the containment pressure boundary.

LRA Table 2.3.2-6 identifies the SGTS component types that are 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 and UFSAR Sections 6.5.1.1 and 6.5.3.2, and LRA Table 2.3.2-6 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 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).

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).

2.3.2.7 Containment Penetrations

2.3.2.7.1 Summary of Technical Information in the Application

LRA Section 2.3.2.7 describes primary and secondary containment penetrations in systems that are not included in another AMR. This section provides a grouping of containment isolation valves from the primary and secondary containment, drywell monitoring, and containment and drywell I&C systems into a consolidated review.

The LRA states that the containment penetrations have an intended function to support containment integrity. The containment penetrations also have an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the containment penetrations have an intended function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48). The drywell monitoring system has an intended function to support the containment pressure boundary. The containment and drywell I&C system has the intended functions to support safety-related pressure instrumentation in the drywell and containment and to support the containment pressure boundary.

LRA Table 2.3.2-7 identifies the containment penetrations component types that are within the scope of license renewal and subject to an AMR.

2.3.2.7.2 Staff Evaluation

The staff reviewed LRA Sections 2.3.2.7, and UFSAR Sections 1.2.2.4.9.1, 5.4.1, 6.2.1.1.3.3.1.1, 6.5.3.1, 7.1.2.1.4.5, 7.7.1.6, 9.2.3, 9.2.4, 9.5.9, 9.2.11, 9.3.6, 9.4.6, 9.4.7, 9.4.8, 11.2, Figures 7.7-10, 7.6.1.4.3.9, 12.3.4.2, and 7.5.1, and LRA Tables 2.3.2-7 and 3.2.2-7, 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 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).

2.3.2.7.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the containment penetrations 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).

2.3.2.8 Miscellaneous Engineering Safety Feature Systems in Scope for 10 CFR 54.4(a)(2)

2.3.2.8.1 Summary of Technical Information in the Application

LRA Section 2.3.2.8 describes the following ESF systems, described in the referenced sections, which are within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(2) for physical interactions.

- RHR (LRA Section 2.3.2.1)
- LPCS (LRA Section 2.3.2.2)
- HPCS (LRA Section 2.3.2.3)
- RCIC (LRA Section 2.3.2.4)

2.3.2.8.2 Staff Evaluation

SER Sections 2.3.2.1 through 2.3.2.4 document the staff evaluation for the individual 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 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).

2.3.2.8.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the miscellaneous ESF systems in scope for 10 CFR 54.4(a)(2) 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, “Control Rod Drive”
- 2.3.3.2, “Standby Liquid Control”
- 2.3.3.3, “Suppression Pool Makeup”
- 2.3.3.4, “Leakage Detection and Control”
- 2.3.3.5, “Combustible Gas Control”
- 2.3.3.6, “Fuel Pool Cooling and Cleanup”
- 2.3.3.7, “Standby Service Water”
- 2.3.3.8, “Component Cooling Water”
- 2.3.3.9, “Plant Service Water”
- 2.3.3.10, “Floor and Equipment Drainage”
- 2.3.3.11, “Compressed Air”
- 2.3.3.12, “Fire Protection – Water”

- 2.3.3.13, “Fire Protection – Halon and CO_2”
- 2.3.3.14, “Plant Chilled Water”
- 2.3.3.15, “Standby Diesel Generator”
- 2.3.3.16, “HPCS Diesel Generator”
- 2.3.3.17, “Control Room Heating, Ventilation and Air Conditioning”
- 2.3.3.18, “Heating, Ventilation and Air Conditioning”
- 2.3.3.19, “Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2)”

The staff’s findings on review of LRA Sections 2.3.3.1 – 2.3.3.19 are in SER Sections 2.3.3.1-2.3.3.19, respectively.

Auxiliary Systems Generic Requests for Additional Information

In RAI 2.3.3-1, dated May 9, 2012, the staff noted LRA Section 2.1 describes the applicant’s scoping methodology, which specifies how systems or components were determined to be included in the scope of license renewal. The staff confirms the inclusion of all components subject to an AMR by reviewing the results of the screening of components within the license renewal boundary. For eight drawing locations, the continuation of piping in scope for license renewal could not be located. The applicant was requested to provide sufficient information to locate the license renewal boundary.

If the continuation cannot be shown on license renewal boundary drawings, then the applicant was requested 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 termination of the scoping boundary. If the scoping classification of a section of the piping changes over the continuation, the applicant was requested to provide additional information to clarify the change in scoping classification.

In its response dated June 5, 2012, the applicant provided information to clarify the extent of the license renewal boundary for each of the eight continuations. In each case, the applicant detailed the routing and location of the piping in question and stated that all relevant component types have been identified in the LRA.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3-1 acceptable because the applicant provided additional information to locate the license renewal boundaries. No new systems or components were added to the scope of license renewal as a result of the response to RAI 2.3.3-1 and no component types were identified that had not been previously evaluated. Therefore, the staff’s concern described in RAI 2.3.3-1 is resolved.

In RAI 2.3.3-2, dated May 9, 2012, the staff noted LRA Section 2.1.2.1.3, “Mechanical System Drawings,” describes the applicant’s development of license renewal drawings. This LRA section does not describe the use of a solid red line in several license renewal drawings to denote the end of the license renewal scoping boundary. Examples of this notation can be found on boundary drawings LRA-M-1061A, LRA-M-1094C, and LRA-M-1109F but is not necessarily limited to these drawings only. The applicant was requested to provide additional information to describe the use of the solid red line on license renewal drawings. For all cases where the red line is used, the applicant was asked to clarify if the piping in question leaves a space that contains components within the scope of license renewal for 10 CFR 54.4(a)(1), at the point of the red line. Additionally, for all cases where the red line is used, the applicant was asked to clarify if the license renewal boundary includes a seismic anchor or equivalent support between the safety-related and nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 5, 2012, the applicant stated solid red lines signify (1) a transition from a drawing that is maintained to a drawing that is not maintained and as such is not provided as an LRA drawing, or (2) a transition through a wall that separates a plant space containing components within the scope of license renewal for 10 CFR 54.4(a)(1) from another space, thus depicting the limit of the potential spatial interaction in this area. In both cases, all nonsafety-related fluid-filled components whose failure could affect safety-related components because of their physical proximity are in scope for 10 CFR 54.4(a)(2) and subject to an AMR. In addition for both cases, seismic anchors or equivalent supports are included as necessary between the safety-related and nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

Based on its review, the staff finds the applicant's response to RAI 2.3.3-2 acceptable because the applicant generically explained the use of the solid red line on boundary drawings and specifically explained for the examples provided in the RAI. Therefore, the staff's concern described in RAI 2.3.3-2 is resolved.

2.3.3.1 Control Rod Drive

2.3.3.1.1 Summary of Technical Information in the Application

The CRD system consists of locking piston CRD mechanisms 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 CRDs. The hydraulic control units manage water flow to and from the control rod. One supply pump pressurizes the system with water from a condensate supply header, which takes suction from the condensate treatment system or condensate storage tanks (CSTs).

The scram accumulators store sufficient energy to fully insert a control rod at any vessel pressure. The accumulator is a hydraulic cylinder with a free-floating piston. The piston separates the water on top from the nitrogen below. During a scram, the scram inlet (and outlet) valves open and permit the stored energy in the accumulators to discharge into the drives.

The scram discharge volume header is designed to receive and contain all the water discharged by each of the hydraulic control units during a scram. The scram discharge volume header drains to an instrument volume.

The alternate rod insertion system consists of three parallel vent paths from the scram pilot air header. The alternate rod insertion system is designed to initiate a scram independent of the reactor protection system. This is accomplished by the opening of two solenoid valves, in series, to depressurize the scram pilot header that actuates the CRD scram valves.

Additional details for components subject to an AMR can be found in UFSAR Section 4.6.1.1.

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

- provide emergency reactor shutdown (SCRAM); manual and automatic
- provide primary containment isolation and integrity
- maintain RCPB integrity

The following highlighted license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

LRA-M-1081A LRA-M-1081B LRA-M-1051A

LRA Tables 2.3.3-1 and 2.3.1-3 list the component types that require AMR and their intended functions.

2.3.3.1.2 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).

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 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).

2.3.3.2 Standby Liquid Control

2.3.3.2.1 Summary of Technical Information in the Application

The standby liquid control (SLC) system consists of a boron solution tank, two positive-displacement pumps, two explosive valves, and associated piping and valves to transfer the borated water from the storage tank to the RPV. The SLC system is manually initiated from the main control room to pump a boron neutron absorber solution into the reactor if the operator determines that the reactor cannot be shut down with the control rods or if suppression pool pH control is required to mitigate the dose consequences of a LOCA. The liquid is piped into the RV and discharged into the core through the HPCS header 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:

- provide borated water to the RCS to bring the reactor to a shutdown condition at any time in the reactor core life

- provide primary containment isolation and integrity
- maintain RCPB integrity

Additional details for components subject to an AMR can be found in UFSAR Sections 6.2.4.3.1.1.6 and 9.3.5.2.

The following highlighted license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

LRA-M-1082

LRA Tables 2.3.3-2 and 2.3.1-2 list the component types that require AMR and their intended functions.

2.3.3.2.2 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).

2.3.3.2.3 Conclusion

On the basis of its LRA and UFSAR review, 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).

2.3.3.3 Suppression Pool Makeup

2.3.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 states that the purpose of the suppression pool makeup system is to transfer water from the upper containment pool to the suppression pool following a LOCA. The water transfer from the suppression pool makeup system ensures the suppression pool top row vents are adequately covered to maintain post-LOCA-long-term steam condensation.

The LRA states that the suppression pool makeup system’s intended functions are to transfer water from the upper containment pool to the suppression pool by gravity flow following a LOCA, to support safety-related suppression pool level instrumentation, and to support the containment pressure boundary.

LRA Table 2.3.3-3 identifies the suppression pool makeup system component types that are 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, UFSAR Section 6.2.7, 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 request for additional information as discussed below.

In RAI 2.3.3.3-1, dated May 9, 2012, the staff noted LRA Table 2.3.3-3 appears to be incorrectly labeled "Suppression Pool Cleanup System Components Subject to Aging Management Review" when it is associated with LRA Section 2.3.3.3, Suppression Pool Makeup. The applicant was requested to clarify the title of LRA Table 2.3.3-3 and verify that all components associated with the suppression pool makeup system subject to an AMR have been identified.

In its response dated June 5, 2012, the applicant stated the title of LRA Table 2.3.3-3 has been revised to "Suppression Pool Makeup System." Table 2.3.3-3 component types include all components associated with the suppression pool makeup system that are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-1 acceptable because the applicant revised the LRA table title and stated all components associated with the system are included within the component types of Table 2.3.3-3. Therefore, the staff's concern described in RAI 2.3.3.3-1 is resolved.

2.3.3.3.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the suppression pool makeup 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).

2.3.3.4 Leakage Detection and Control

2.3.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 states that the purpose of the leak detection system is to detect, annunciate, and isolate leakages in systems that are part of or connected to the RCPB or the fuel pool cooling system. The leak detection system consists of temperature, pressure, radiation, flow, and level sensors with associated instrumentation and alarms.

The LRA states that the leakage detection and control system's intended functions are to monitor leakage from the fuel pool, to maintain integrity of the RCPB, and to support the containment pressure boundary. The leakage detection and control system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-4 identifies the leakage detection and control system component types that are 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 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. 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).

2.3.3.4.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the leakage detection and 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).

2.3.3.5 Combustible Gas Control

2.3.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 states that the purpose of the combustible gas control system is to control the concentration of hydrogen, which may be released in the drywell and containment following a LOCA. Three subsystems provide hydrogen gas control: the drywell purge system, the hydrogen control system, and the backup containment purge system. The hydrogen ignition system is used to control the excessive quantity of hydrogen generated during the occurrence of a degraded core accident. The drywell purge compressors dilute post-LOCA drywell radionuclide concentrations.

The LRA states that the combustible gas control system's intended functions are to control the concentration of hydrogen released in the drywell and containment following a LOCA, to dilute the drywell atmosphere with containment air and purge the drywell atmosphere into the containment, to induce the controlled combustion of hydrogen in containment, to provide drywell vacuum relief protection relative to the containment, and to support the containment pressure boundary. The combustible gas control system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-5 identifies the combustible gas control 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 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).

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 combustible gas 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).

2.3.3.6 Fuel Pool Cooling and Cleanup

2.3.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 describes the fuel pool cooling and cleanup and the servicing equipment systems. The purpose of the fuel pool cooling and cleanup system is to maintain acceptable temperature, clarity, and radioactivity levels of the water in the upper containment, fuel storage, and cask pools. The servicing equipment systems include tools and equipment used primarily during refueling outages.

The LRA states that the fuel pool cooling and cleanup system's intended functions are to remove the decay heat from spent fuel assemblies, to monitor fuel pool water level and maintain a water level above the fuel sufficient to provide radiation shielding, and to support the containment pressure boundary. The fuel pool cooling and cleanup system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. The servicing equipment systems have an intended function to provide criticality protection that is performed by Boraflex plates in the pool racks.

LRA Table 2.3.3-6 identifies the fuel pool cooling and cleanup system component types that are 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 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).

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 spent 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).

2.3.3.7 Standby Service Water

2.3.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 states that the purpose of the SSW system is to remove heat from equipment required for a safe reactor shutdown by dissipating that heat to the environment through the ultimate heat sink. The SSW system also provides cooling to unit components, as required, during normal shutdown and reactor isolation modes.

The LRA states that the SSW system's intended functions are to supply cooling water to safety-related systems and components during plant shutdown, reactor isolation, refueling and post-accident conditions; to transfer heat from safety-related loads to the environment; and to support the containment pressure boundary. The SSW system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the SSW system has an intended function to demonstrate compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.3-7 identifies the SSW system component types that are 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, 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 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. The applicant responded to the staff's request for additional information as discussed below.

In RAI 2.3.3.7-1, dated May 9, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are in scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety-related interface. In three instances the staff could not locate seismic anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines connected to the safety-related lines. The applicant was requested to provide additional information to locate the seismic anchors between the safety-related and nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 5, 2012, the applicant described the specific location of the seismic anchors or identified equivalent anchors for the three anchors in question.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1 acceptable because the applicant provided a description of the location of the anchors, which were at appropriate locations on the nonsafety-related lines. 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 that 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).

2.3.3.8 Component Cooling Water

2.3.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 states that the purpose of the component cooling water system is to cool auxiliary plant equipment during normal operating and normal shutdown conditions. The system also provides cooling water for some components during a loss of offsite power.

The LRA states that the component cooling water's intended functions are to maintain integrity of the SSW system pressure boundary, and to support the containment pressure boundary. The component cooling water also has an intended function to maintain the integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-8 identifies the component cooling water system component types that are 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 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. 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).

2.3.3.8.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the component 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).

2.3.3.9 Plant Service Water

2.3.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 states that the purpose of the plant service water system is to cool plant auxiliary equipment during normal operating and normal shutdown conditions. The system is designed to cool plant auxiliaries that are not required for safe reactor shutdown and are not potential sources of radioactive contamination during normal operation. The plant service water system distributes water from the radial well system through the various heat exchangers, chillers and coolers, and discharges to the circulating water (CW) system.

The LRA states that the plant service water system's intended functions are to maintain integrity of the SSW system pressure boundary and to support the containment pressure boundary. The plant service water system also has the intended functions to support the containment pressure boundary and to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-9 identifies the plant service water system component types that are 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, UFSAR Section 9.2.8, 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 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. The applicant responded to the staff's request for additional information as discussed below.

In RAI 2.3.3.9-1, dated May 9, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are in scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety-related interface. On license renewal boundary drawing LRA-M-1072A, location B-5, the staff could not locate a seismic anchor at safety-related valve Q1P44F116 (anchor could not be located on (a)(2) branch line 24"-JBD-77 continuing to line 30"-JBD-77 continuing to drawing LRA-M-1059A, A-8). The applicant was requested to provide additional information to locate the seismic anchors between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 5, 2012, the applicant described the location of the anchor on the nonsafety-related piping 24"-JBD-77 attached to the safety-related piping at valve Q1P44F116.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-1 acceptable because the applicant the appropriate location of the anchor in question, which is at an acceptable location between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff's concern described in RAI 2.3.3.9-1 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 plant service water 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 Floor and Equipment Drainage

2.3.3.10.1 Summary of Technical Information in the Application

LRA Section 2.2.2.10 states that the purpose of the floor and equipment drainage system is to collect liquid waste throughout the plant and discharge the radioactive and potentially radioactive waste to the radwaste system for processing. The system is also used to detect abnormal leakage in the emergency safety features rooms, the drywell, and containment.

The LRA states that the floor and equipment drainage system's intended function is to support the containment pressure boundary. The floor and equipment drainage system also has the intended functions to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function and to provide flood protection for safety-related components.

LRA Table 2.3.3-10 identifies the floor and equipment drainage system component types that are 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, UFSAR Section 9.3.3, 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 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. The applicant responded to the staff's request for additional information as discussed below.

In RAI 2.3.3.10-1, dated May 9, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/ nonsafety-related interface. At 10 locations, the staff could not locate a seismic anchor on the 10 CFR 54.4(a)(2) nonsafety-related lines connected to the safety-related line. The applicant was requested to provide additional information to locate the seismic anchors between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 5, 2012, the applicant described the location of the 10 seismic and/or equivalent anchors.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.10-1 acceptable because the applicant provided the location of these 10 seismic and/or equivalent anchors, which were at acceptable locations. Therefore, the staff's concern described in RAI 2.3.3.10-1 is resolved.

2.3.3.10.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes that the applicant appropriately identified the floor and equipment 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).

2.3.3.11 Compressed Air

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 describes the compressed air and hatches and locks systems. The purpose of the compressed air systems is to provide a continuous supply of compressed air of suitable quality and pressure to air operated components throughout the plant and for general plant use. The compressed air systems include the plant compressed air, service air, and instrument air systems. The hatches and locks system includes the containment and drywell equipment hatches, the containment personnel airlocks, and the drywell airlock. The purpose of the equipment hatches is to provide equipment access to the containment and drywell during outages. The purpose of the airlocks is to provide personnel access to the containment and drywell while also providing a continuous seal between the inside and outside of the containment or drywell.

The LRA states that the compressed air system's intended function is to support the containment pressure boundary. The compressed air system also has the intended functions to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function and to support the containment pressure boundary. The hatches and locks system has the intended functions to provide a reserve capacity of compressed air for those components requiring a supply of compressed air to provide ESF and containment pressure boundary and to support the containment pressure boundary.

LRA Table 2.3.3-11 identifies the compressed air system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11, UFSAR Section 9.3.1, 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 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 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 2.3.3.11-1, dated May 9, 2012, the staff noted that license renewal boundary drawing LRA-M-1077A, locations C-6 and H-6, and LRA-M-1077D, locations D-6 and G-6, show

1"-JDD-19 lines to be in scope for 10 CFR 54.4(a)(1) with continuations from drawing LRA-M-1067A. However, the continuations of these lines on license renewal boundary drawing LRA-M-1067A are shown as not in scope. The applicant was requested to provide additional information to clarify the scoping classification of these pipe sections.

In its response dated June 5, 2012, the applicant stated that the 1"-JDD-19 lines were inadvertently highlighted to the check valves and that they are not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.11-1 and correction to remove the 1"-JDD-19 lines from the scope of license renewal acceptable because upstream of check valves F024A, B, C, and D, the 1"-JDD-19 lines are nonsafety-related and not fluid filled. Therefore, the staff's concern described in RAI 2.3.3.11-1 is resolved.

In RAI 2.3.3.11-2, dated May 9, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are in scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety-related interface. In four locations, the staff could not locate seismic anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines connected to safety-related lines: The applicant was requested to provide additional information to locate the seismic anchors between the safety-related/ nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 5, 2012, the applicant described the location of the four seismic and/or equivalent anchors.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.11-2 acceptable because the applicant described the location of the seismic and/or equivalent anchors, which were appropriately located at the end of the 10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff's concern described in RAI 2.3.3.11-2 is resolved.

2.3.3.11.3 Conclusion

On the basis of its review of the LRA, UFSAR, and RAI responses, the staff concludes that the applicant appropriately identified the compressed air 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).

2.3.3.12 Fire Protection – Water

2.3.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 describes the purpose of the fire protection system, which is to provide an adequate supply of water or chemicals to points throughout the plant area where fire protection may be required. The fire protection system consists of fire water suppression subsystems, chemical firefighting equipment, portable fire extinguishers, portable breathing apparatus, and the I&C for fire detection, alarm, and operation of the fire-fighting systems. The halon and CO_2 systems are described in LRA Section 2.3.3.13.

The LRA states that the fire protection – water system has an intended function to support the containment pressure boundary. The system also has the intended function to support the containment pressure boundary and to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the fire protection – water system has an intended function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.3-12 identifies the fire protection – water system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.12.2 Staff Evaluation

The staff reviewed the LRA Section 2.3.3.12; the UFSAR, Revision 5; and LRA drawings using the evaluation methodology described in the 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 had not omitted from the scope of license renewal any components with intended functions in accordance with the requirements of 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 had not omitted any 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 documents cited in the CLB listed in the GGNS Operating License Condition 41:

- NRC SERs dated August 23, 1991, and September 29, 2006

Based on the documents above, the staff reviewed the GGNS 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 Branch Technical Position (BTP) Auxiliary Systems Branch 9.5-1, documented in the UFSAR Table 9.5-11.

During its review of LRA Section 2.3.3.12, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results.

In its letter dated May 29, 2012, the staff issued RAI 2.3.3.12-1 and stated that Section 9.5.1.1, "Water Supply System," of the SER dated September 1981, discussed the radwaste building water supply system. The staff notes that LRA boundary drawing LRA-M-0035G shows the radwaste building fire water system as out of scope (i.e., not colored in purple). The staff requested that the applicant verify whether the radwaste building fire water system is 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). If the system is excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant provide justification for the exclusion.

In a letter dated June 22, 2012, the applicant responded to RAI 2.3.3.12-1 and stated that the portions of the fire protection system in the radwaste building include no equipment credited with fire prevention, detection, or mitigation in areas containing equipment important to safe operation of the plant or systems that contain plant components credited for safe shutdown following a fire per 10 CFR 50.48. Therefore, the portions of the fire protection system in the radwaste building perform no intended function for license renewal and are not in the scope and not subject to an AMR.

The staff found that the applicant's analysis of fire protection regulations does not completely capture the fire protection SSCs required for compliance with 10 CFR 50.48. The applicant indicated that the fire suppression systems in question perform no intended function in support of the plant license renewal and, therefore, are excluded from the scope of license renewal and not subject to an AMR. The staff finds this contrary to the commitments the applicant made to satisfy BTP APCSB 9.5-1, Appendix A, Position F.14, "Radwaste Building" (i.e., that the automatic sprinklers are provided for the oil separator in the radwaste building to meet the guidance of Appendix A to BTP APCSB 9.5-1). Therefore, the fire suppression systems and components in question should be operable to meet 10 CFR 50.48 (in accordance with the CLB) as stated in 10 CFR 54.4(a)(3). In addition, fire suppression systems and components should not be excluded on the basis that they are not required to function to suppress a fire or to comply with 10 CFR 50.48, without factoring in the CLB.

By letter dated July 27, 2012, the staff issued follow-up RAI 2.3.3.12-1a, requesting the applicant clarify why the radwaste building oil separator automatic sprinklers 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 response dated August 21, 2012, the applicant stated that the fire suppression system components associated with the radwaste building oil separator automatic sprinklers (oil waste room) will be included in the scope of license renewal and subject to an AMR. The Fire Water System Program will manage the effects of aging for those components. The component/material/environment combinations associated with these components are already included in LRA Table 3.3.2-12 for carbon steel piping, gray cast iron valve bodies with internal raw water and indoor air external environments and copper alloy greater than 15 percent zinc or greater than 8 percent aluminum nozzles and valve bodies with raw water environment internal and indoor air external.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.12-1a acceptable because it clarifies that the radwaste building oil separator automatic sprinklers in question are in the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3.3.12-1 is resolved.

In its letter dated May 29, 2012, the staff issued RAI 2.3.3.12-2 and stated that the LRA boundary drawing listed below shows the following fire protection systems or components as out of scope (i.e., not colored in yellow):

LRA Drawing	Systems/Components	Location
LRA-M-0035L	Fire water suppression systems associated with Emergency Safety Features Transformers, ESF11 and ESF21	H3

The staff requested that the applicant verify whether the fire protection systems or components listed above are in the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). If they are excluded from the scope of license renewal and are not subject to an AMR, the staff requested that the applicant provide justification for the exclusion.

In a letter dated June 22, 2012, the applicant responded to RAI 2.3.3.12-2 and stated that the Transformers ESF11 and ESF21 are the nonsafety-related source of power to engineered safeguards busses at GGNS during normal operation. The portions of the fire protection system associated with transformers ESF11 and ESF21 include no equipment credited with fire prevention, detection, or mitigation in areas containing equipment important to safe operation of the plant or systems that contain plant components credited for safe shutdown following a fire per 10 CFR 50.48. The fire protection system components associated with emergency safety features transformers ESF11 and ESF21 perform no license renewal intended function and, therefore, are not in the scope of license renewal and subject to an AMR.

The staff finds that the applicant's analysis of fire protection regulations does not completely capture the fire protection SSCs required for compliance with 10 CFR 50.48. The applicant indicated that the fire suppression systems in question perform no intended function in support of the plant license renewal and, therefore, are excluded from the scope of license renewal and not subject to an AMR. The staff finds this contrary to the commitments the applicant made to satisfy BTP APCSB 9.5-1, Appendix A, Position D.1(h) and Grand Gulf Fire Hazard Analysis Report, Appendix 9A, Section 9A.5.59.2, "Safe Shutdown Equipment." The applicant's CLB demonstrates that the ESF11 and ESF21 transformer fire suppression systems were credited to meet the guidance of Appendix A to BTP APCSB 9.5-1. Therefore, the fire suppression systems and components in question should be operable to meet 10 CFR 50.48 (in accordance with the CLB) as stated in 10 CFR 54.4(a)(3). In addition, fire suppression systems and components should not be excluded on the basis that they are not required to function to suppress a fire or to comply with 10 CFR 50.48, without factoring in the CLB.

By letter dated July 27, 2012, the staff issued follow-up RAI 2.3.3.12-2a, requesting that the applicant clarify why the Transformer ESF11 and ESF21 fire suppression systems 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 Transformer ESF11 and ESF21 fire suppression systems from the scope of license renewal and an AMR.

In a letter dated August 21, 2012, the applicant responded to RAI 2.3.3.12-2a and stated that the fire suppression system components associated with the ESF11 and ESF21 transformers will be included in the scope of license renewal and subject to an AMR. The Fire Water System Program will manage the effects of aging for those components. The component/material/environment combinations associated with these components are already included in LRA Table 3.3.2-12 for carbon steel piping, strainer housings, valve bodies with internal raw water and indoor air external environments and copper alloy greater than 15 percent zinc or greater than 8 percent aluminum strainers with raw water environment internal and external, as well as carbon steel piping with outdoor-air internal and external and also with soil external. Further the applicant stated the items are added to Table 3.3.2-12 for nozzles in the outdoor air environment as shown below. Changes are shown with additions underlined.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that the fire suppression systems associated with the ESF11 and ESF21 transformers are in the scope of license renewal and subject to an AMR. Further, the applicant has updated LRA Table 3.3.2-12 and to include the nozzle component type. The staff's concern described in RAI 2.3.3.12-1 is resolved.

In its letter dated May 29, 2012, the staff issued RAI 2.3.3.12-3 and asked the applicant to determine if LRA Tables 2.3.3-12 and 3.3.2-12 should include the following fire protection components:

- fire hose connections and hose racks
- pipe supports, hangers, and couplings
- yard fire hydrants
- water sprinklers and hose standpipes
- floor drains for fire water
- fire water systems associated with SGTS charcoal filters and containment exhaust system charcoal filters
- fire water supply filter housings
- dikes and curbs for oil spill confinement

If the applicant determined that LRA Tables 2.3.3-12 and 3.3.2-12 should not include these components, the staff asked that the applicant justify the exclusion of these components from the scope of license renewal.

In its response, dated June 22, 2012, the applicant provided the results of the scoping and screening for the listed fire protection component types addressed in RAI 2.3.3.12-3. Although the description of the "piping" item provided in LRA Table 2.3.3-12 does not list these components specifically, the applicant stated that it considers this item to include the fire hose connection, couplings, and hose standpipes. LRA Table 3.3.2-12 provides the AMR results of these components. The applicant indicated that the hose racks and pipe support and hangers are included in the structural AMR under component types "fire hose reels" and "component and piping support," respectively, in LRA Table 3.5.2-4. The applicant also confirmed that yard fire hydrants are in the scope of license renewal and subject to an AMR. Yard fire hydrants are included in LRA AMR Table 3.3.2-12 as the "valve body" component types. In its response, the applicant also confirmed that "sprinklers" are included in component type "nozzle" in LRA Table 2.3.3-12, with AMR results provided in LRA Table 3.3.2-12. The floor drains are included in LRA Tables 2.3.3-10 and 2.3.3.19-20 under component type "piping" with the AMR results provided in LRA Tables 3.3.2-10 and 3.3.2-19-20. The applicant indicated that the fire water systems associated with SGTS charcoal filters and containment exhaust system charcoal filters are in the scope of license renewal and subject to an AMR and highlighted on LRA drawing LRA-M-0035B-0 at locations B7 and D6. Fire water supply filter housings are included in component types "strainer housing" in LRA Table 2.2.3-12 with the AMR results provided in LRA Table 3.3.2-12. In addition, the applicant indicated that the dikes and curbs for oil spill confinement are included in the structural AMR under component type "floor slabs" and "interior wall" (for concrete) in LRA Table 2.4-2, with the AMR results provided in LRA Table 3.5.2-2.

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 2.3.3.12-3 acceptable for the purpose of determining whether the applicant has adequately identified the fire protection system components within the scope of license renewal.

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 fire protection – water 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 Fire Protection – Halon and CO_2

2.3.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the purpose of the fire protection system, which is to provide an adequate supply of water or chemicals to points throughout the plant area where fire protection may be required. The fire protection system consists of fire water suppression subsystems, chemical firefighting equipment, portable fire extinguishers, portable breathing apparatus, and the I&C for fire detection, alarm, and operation of the fire-fighting systems. The fire protection – water system is described in LRA Section 2.3.3.12.

The LRA states that the fire protection – halon and CO_2 system has an intended function to support the containment pressure boundary. The system also has an intended function to demonstrate compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.3-13 identifies the fire protection – halon and CO_2 system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.13.2 Staff Evaluation

The staff reviewed the LRA Section 2.3.3.13; the UFSAR, Revision 5; and LRA drawings using the evaluation methodology described in the 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 had not omitted from the scope of license renewal any components with intended functions in accordance with the requirements of 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 had not omitted any 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 documents cited in the CLB listed in the GGNS Operating License Condition 41:

- NRC SERs dated August 23, 1991 and September 29, 2006

Based on the documents above, the staff reviewed the GGNS commitment to 10 CFR 50.48 (i.e., approved Fire Protection Program). The review consisted of a point-by-point comparison with Appendix A to (BTP) Auxiliary Systems Branch 9.5-1, documented in the UFSAR Table 9.5-11.

During its review of LRA Section 2.3.3.13, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results.

In its letter dated June 22, 2012, the staff issued RAI 2.3.3.13-1 and stated that the LRA boundary drawings listed below show the following fire protection systems or components as out of scope (i.e., not colored in blue):

LRA Drawing	Systems/Components	Location
LRA-M-0035E	Pressure relief valves, piping, and components associated with carbon dioxide (CO_2) fire suppression system	G3

LRA Drawing	Systems/Components	Location
LRA-M-0035F	Halon 1301 fire suppression system in:	
	Division III Switchgear Room	C4
	Emergency Remote Shutdown Panel	E4
	Room OC 405	G4
	Division I Switchgear Room	A6
	Control Cabinet Room	F6
	Room OC 406	B8
	Room OC 705	F8

The staff requested that the applicant verify whether the fire protection systems or components listed above are in the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). If they are excluded from the scope of license renewal and are not subject to an AMR, the staff requested that the applicant provide justification for the exclusion.

In a letter dated June 22, 2012, the applicant responded to RAI 2.3.3.13-1 and stated that the pressure relief valves, piping, and components on LRA-M-0035E location G3 that are not highlighted are used to provide CO_2 to purge the main generator of hydrogen or air. This portion of the carbon dioxide system performs no license renewal intended function since it includes no equipment credited with fire prevention, detection, or mitigation in areas containing equipment important to safe operation of the plant or systems that contain plant components credited for safe shutdown following a fire per 10 CFR 50.48.

The portions of the Halon 1301 fire suppression system shown on LRA-M-0035F in the locations listed above are not in scope for license renewal since they include no equipment credited with fire prevention, detection, or mitigation in areas containing equipment important to safe operation of the plant or systems that contain plant components credited for safe shutdown following a fire per 10 CFR 50.48. As indicated in Note 3 of the drawing, the components were intended to serve Unit 2 and are not functional. This note is provided on the drawing for each line listed above.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.13-1 acceptable because the applicant explained that the portion of the CO_2 system in question is used for main generator purge, not for plant fire protection, and does not have a license renewal intended function, and is, therefore excluded from the scope of license renewal and is not subject to an AMR. For the portion of the Halon 1301 fire suppression system in question, the applicant clarifies that this portion is associated with GGNS Unit 2, which is not functional.

2.3.3.13.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI responses, the staff concludes the applicant appropriately identified the fire protection – halon and CO_2 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 Plant Chilled Water

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 states that the purpose of the plant chilled water system is to provide chilled water to the nonsafety-related turbine building, control building, radwaste building, auxiliary building, diesel generator building, and containment fan-coil units for space cooling and dehumidification. The system also supplies cooling water for the sample coolers located throughout the plant. A chemical addition tank is available to chemically treat the system to prevent corrosion and an expansion tank is provided to pressurize the system.

The LRA states that the plant chilled water system's intended function is to support the containment pressure boundary. The plant chilled water system also has the intended functions to support the containment pressure boundary and to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-14 identifies the plant chilled water system component types that are 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 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. 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).

2.3.3.14.3 Conclusion

On the basis of the staff review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the plant chilled 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).

2.3.3.15 Standby Diesel Generator

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 states that the purpose of the standby diesel generator system is to provide power in the event of a loss of offsite power to the ESF electrical loads for safe reactor shutdown and to mitigate the consequences of a DBA such as a LOCA. Standby alternating current (AC) power is supplied by three diesel generators. Each ESF division is supplied by a separate diesel generator. The standby diesel generator auxiliary subsystems include the fuel oil, cooling water, starting air, lubricating oil, and combustion air intake and exhaust systems.

The LRA states that the standby diesel generator system's intended function is to supply standby power to the Division 1 and 2 safety-related equipment required to shut down the reactor, maintain the reactor in a safe shutdown condition, and mitigate the consequences of an accident, in the event of a loss of preferred power. The standby diesel generator also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the standby diesel generator has an intended function to demonstrate compliance with the NRC‘s regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.3-15 identifies the standby diesel generator system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. 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).

2.3.3.15.3 Conclusion

On the basis of the staff review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the standby diesel generator 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 HPCS Diesel Generator

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 describes the purpose of the HPCS diesel generator system, which is to provide power, in the event of a loss of offsite power, to the HPCS pump motor and supporting system components. In conjunction with the standby diesel generator system, the HPCS diesel generator system provides power for safe reactor shutdown and to mitigate the consequences of a DBA such as a LOCA. The HPCS diesel generator auxiliary subsystems include fuel oil, cooling water, starting air, lubricating oil, and combustion air intake and exhaust.

The LRA states the HPCS diesel generator system’s intended function is to supply standby power to the Division 3 safety-related equipment of the HPCS and supporting systems required for the operation of the HPCS system in the event of a loss of preferred power. The HPCS diesel generator system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-16 identifies the HPCS diesel generator 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, UFSAR Sections 8.3.1.1, 9.5.4, 9.5.5, 9.5.6, 9.5.7, and 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 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 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 2.3.3.16-1, dated May 9, 2012, the staff noted license renewal boundary drawings LRA-M-1093B and LRA-M-1093C, location E-3 and E-7, respectively, show fuel injector casings as not within scope for 10 CFR 54.4(a)(1) and not listed in Table 2.3.3-16 as a component type subject to an AMR. However, the piping attached to the fuel injector casings is within the scope of license renewal for 10 CFR 54.4(a)(1). The applicant was requested to justify not including the fuel injector casings within the scope of license renewal for 10 CFR 54.4(a)(1) and to justify why the injector casing component type was excluded from LRA Table 2.3.3-16.

In its response dated June 5, 2012, the applicant stated the fuel injector casings are subcomponents and integral parts of a complex assembly (HPCS diesel generators) and per the guidance in NEI 95-10, Revision 6, Appendix B, the injectors are not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.16-1 acceptable because the injectors are integral components of the diesel generator, which is not subject to AMR. Therefore, the staff's concern described in RAI 2.3.3.16-1 is resolved.

In RAI 2.3.3.16-2, dated May 9, 2012, the staff noted license renewal boundary drawing LRA-M-1093A shows fuel pipeline continuations between the diesel generator fuel oil day tank and both Engine A on drawing LRA-M-1093B and Engine B on drawing LRA-M-1093C. The drawings show there is only a single diesel generator fuel oil day tank and single diesel generator fuel oil storage tank for the HPCS diesel generator.

The LRA Section 2.3.3.16 description of the HPCS diesel generator, Fuel Oil section, states, "[t]he HPCS diesel generator fuel oil system consists of storage tanks, transfer pumps, fuel oil day tanks..." This implies there are multiple storage tanks and day tanks in the system. The applicant was requested to provide additional information to clarify whether there is one or multiple diesel generator fuel oil day tank(s) and diesel generator fuel oil storage tank(s) for the HPCS diesel generator.

In its response dated June 5, 2012, the applicant stated LRA Section 2.3.3.16 was revised to clarify that there is only one fuel oil storage tank and one fuel oil day tank for the HPCS diesel generator.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.16-2 acceptable because the applicant has revised Section 2.3.3.16 to reflect that there is only one fuel oil storage tank and one fuel oil day tank for the HPCS diesel generator. Therefore, the staff's concern described in RAI 2.3.3.16-2 is resolved.

2.3.3.16.3 Conclusion

On the basis of its review of the LRA, UFSAR, and RAI responses, the staff concludes the applicant appropriately identified the HPCS diesel generator 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 Control Room Heating, Ventilation and Air Conditioning

2.3.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 states that the purpose of the control room heating, ventilation, and air conditioning (HVAC) system is to provide an environment in the control room suitable for the operation of safety-related equipment under accident conditions and for the comfort and safety of the operators. The system includes the control room air conditioning and standby fresh air subsystems.

The LRA states that the control room HVAC system's intended functions are to provide a suitable environment during normal and accident conditions for the operation of safety-related equipment in the control room envelope and to limit operator exposure to hazardous chemical and radioactive releases. The control room HVAC system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

LRA Table 2.3.3-17 identifies the control room HVAC 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 and UFSAR Sections 6.4 and 9.4.1, and LRA Table 2.3.3-17, 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 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).

2.3.3.17.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the control room HVAC 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).

2.3.3.18 Heating, Ventilation and Air Conditioning

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 describes the HVAC system, which is divided into the following HVAC subsystems:

- Containment Cooling
- Drywell Cooling
- Auxiliary Building Ventilation
- Fuel Handling Area Ventilation
- ESF Electrical Switchgear Rooms Cooling
- Emergency Pump Room Ventilation
- Turbine Building Ventilation
- Diesel Generator Building Ventilation
- Standby Service Water Pumphouse Ventilation
- Fire Water Pumphouse Ventilation
- Control Building HVAC
- Emergency Switchgear and Battery Rooms Ventilation

The SGTS and control room HVAC system are described in LRA Sections 2.3.2.6 and 2.3.3.17, respectively. Building louvers mounted in the external walls and fire dampers are included in LRA Section 2.4.

The LRA states that the HVAC system has the intended functions to support the containment pressure boundary; to maintain a suitable room temperature to support operation of the ESF electrical switchgear, equipment in the ECCS pump rooms and associated piping penetration rooms, equipment in the RCIC pump room, equipment in the fuel pool cooling and cleanup pump room during loss of normal ventilation, equipment in the diesel generator rooms when the diesels are operating, equipment in SSW pumphouse A and B when the SSW and HPCS service water pumps are operating, batteries and switchgear, safety-related equipment in the control building HVAC equipment room under accident and post-accident conditions; and to provide combustion air to the diesel generators, to maintain a slight negative pressure in the battery rooms to prevent ex-filtration of hydrogen and maintain battery room hydrogen concentrations within acceptable levels with dilution air and exhaust flow. The HVAC system also has the intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the HVAC system has an intended function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.3-18 identifies the HVAC component types that are 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 and UFSAR Sections 6.2.1.1.2.6, 9.4.2, and 9.4.4-9.4.10, and LRA Table 2.3.3-18, 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 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).

2.3.3.18.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the HVAC 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).

2.3.3.19 Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2)

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 describes auxiliary systems that are within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(2) for physical interactions. The following auxiliary systems are described in individual system sections, as noted:

- CRD (LRA Section 2.3.3.1)
- SLC (LRA Section 2.3.3.2)
- leakage detection and control (LRA Section 2.3.3.4)
- combustible gas control (LRA Section 2.3.3.5)
- SSW (LRA Section 2.3.3.7)
- component cooling water (LRA Section 2.3.3.8)
- plant service water (LRA Section 2.3.3.9)
- floor and equipment drainage (LRA Section 2.3.3.10)
- compressed air (LRA Section 2.3.3.11)
- fire protection – water (LRA Section 2.3.3.12)
- plant chilled water (LRA Section 2.3.3.14)
- standby diesel generator (LRA Section 2.3.3.15)
- HPCS diesel generator (LRA Section 2.3.3.16)
- Control Room HVAC (LRA Section 2.3.3.17)
- HVAC (LRA Section 2.3.3.18)
- miscellaneous auxiliary systems in scope for 10 CFR 54.4(a)(2) (LRA Section 2.3.3.19)

The LRA describes the following additional systems that are within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(2) for physical interactions:

- process radiation monitoring
- reactor water cleanup
- CRD maintenance facility, flush tank filter, and leak test
- containment leak rate test
- auxiliary steam
- makeup water treatment
- process sampling
- turbine building cooling water
- suppression pool cleanup
- domestic water
- drywell chilled water

- NobleChem^{TM} injection and monitoring
- sanitary waste

The LRA states that these systems have an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19, UFSAR Sections 5.4.8, 6.2.6, 7.6, 9.2.3, 9.2.4, 9.2.9, 9.2.11, 9.3.2, 9.3.6, 9.5.9, and 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 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 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 2.3.3.19-1, dated May 14, 2012, the staff noted LRA Section 2.1.1.2.2(1) indicates that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety-related interface. In three locations, the staff could not locate in the makeup water treatment system seismic anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines connected to safety-related lines. The applicant was requested to provide additional information to locate the seismic anchors between the safety-related and nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 11, 2012, the applicant provided information to locate the three seismic anchors or equivalent anchors between the safety-related/nonsafety-related interfaces.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-1 acceptable because the applicant described the location of the seismic or equivalent anchors, which were at appropriate locations between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff's concern described in RAI 2.3.3.19-1 is resolved.

In RAI 2.3.3.19-2, dated May 14, 2012, the staff noted auxiliary steam system license renewal boundary drawing LRA-M-0036C, location D-6, shows line 1"-HBD-1108 I-"E" as within the scope of license renewal for 10 CFR 54.4(a)(2). The drawing also shows a portion of the connecting clean radwaste (CRW) drain line (1-1/2"-HBD-1108 1-"E" line) as within the scope of license renewal for 10 CFR 54.4(a)(2). However, there is no separation (i.e., valve) between the in-scope portion of this CRW drain line and the out-of-scope portion of the auxiliary steam system. The applicant was requested to provide additional information to clarify the scoping classification of this pipe section.

In its response dated June 11, 2012, the applicant stated that the scoping should have extended to the closed isolation valve, F098. The applicant also confirmed the addition of “piping” and “valve body” to LRA Table 3.3.2-19-2.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.19-2 acceptable because the applicant included, within the scope of license renewal, the closed isolation valve (F098) that separates the in-scope portion of this CRW drain line and the out-of-scope portion of the auxiliary steam system. Therefore, the staff’s concern described in RAI 2.3.3.19-2 is resolved.

In RAI 2.3.3.19-3, dated May 14, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/ nonsafety-related interface. On reactor water cleanup system license renewal boundary drawing LRA-M-1080B, location G-4, the staff could not locate a seismic anchor on the nonsafety-related piping downstream of safety-related line 4"-HBC-355, where the pipe leaves the auxiliary building. The applicant was requested to provide additional information to locate the seismic anchor between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 11, 2012, the applicant described the location the seismic anchor on nonsafety-related piping 4"-HBD-759 connected to safety-related piping 4"-HBC-355.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.19-3 acceptable because the applicant described the location of the seismic anchor, which is located appropriately between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff’s concern described in RAI 2.3.3.19-3 is resolved.

In RAI 2.3.3.19-4, dated May 14, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/ nonsafety-related interface. On domestic water system license renewal boundary drawing LRA-M-0034B, location F-3, the staff could not locate the seismic anchor on the nonsafety-related 3"-HCD-439 line connected to safety-related line 3"-HCC-65. The applicant was requested to provide additional information to locate the seismic anchor between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 11, 2012, the applicant described the location of the anchor on nonsafety-related piping 3"-HCD-439 attached to safety-related piping 3"-HCC-65.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.19-4 acceptable because the applicant described the location of the seismic anchor, which was at an appropriate location between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff’s concern described in RAI 2.3.3.19-4 is resolved.

In RAI 2.3.3.19-5, dated May 14, 2012, the staff noted containment leak rate test system license renewal boundary drawing LRA-M-1072F, location B-3 and B-4, shows the after cooler and refrigerated air dryer as not within the scope of license renewal. However, the lines connecting to these two components are shown as in scope for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to clarify the scoping classification of the after cooler and refrigerated air dryer.

In its response dated June 11, 2012, the applicant stated the shell side of the aftercooler and refrigerated air dryer contains compressed air; the tube sides are liquid filled. Any leakage or spray from the tubes within the aftercooler and air dryer is contained in the housing and will not affect safety-related components; consequently, the tubes are not in the scope of license renewal. The housing is included in scope as “piping” in LRA Table 2.3.3-19-12 and included in the aging management evaluation in LRA Table 3.3.2-19-12.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.19-5 acceptable because the aftercooler and refrigerated air dryer housings are in scope for license renewal and are included in Table 3.3.2-19-12 as component types subject to an AMR. Therefore, the staff’s concern described in RAI 2.3.3.19-5 is resolved.

In RAI 2.3.3.19-6, dated May 14, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety-related interface. On containment leak rate test system license renewal boundary drawing LRA-M-1111A, locations E-7, D-7, and C-7, the staff could not locate the seismic anchors on the nonsafety-related lines connected to safety-related lines 1"-HCB-36,1"-HCB-37, and 1"-HCB-38. The applicant was requested to provide additional information to locate the seismic anchors between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 11, 2012, the applicant stated the containment leak rate system is disconnected after testing where the highlighting ends on the drawing and is not part of the containment pressure boundary and is not in scope.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.19-6 acceptable because the equipment beyond the drawing highlighting is temporary and therefore not subject to AMR. Therefore, the staff’s concern described in RAI 2.3.3.19-6 is resolved.

In RAI 2.3.3.19-7, dated May 14, 2012, the staff noted LRA Section 2.1.1.2.2(1) states that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety-related interface. On process sampling system license renewal boundary drawing LRA-M-1069D, the staff could not locate seismic anchors on the 10 CFR 54.4(a)(2) nonsafety-related line between the safety-related/nonsafety-related interface at location H-8 and the end of the 10 CFR 54.4(a)(2) scoping boundary at valve SV-F572, location H-3. The applicant was requested to provide additional information to locate the seismic anchor between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 11, 2012, the applicant described the location of the equivalent anchor between the safety-related/nonsafety-related interfaces.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.19-7 acceptable because the applicant described the location of the seismic anchor, which was at an appropriate location between the safety-related/nonsafety-related interface and the end of the

10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff's concern described in RAI 2.3.3.19-7 is resolved.

In RAI 2.3.3.19-8, dated May 14, 2012, the staff noted process sampling system license renewal boundary drawing LRA-M-1069D shows various sampling lines within the scope of license renewal for 10 CFR 54.4(a)(2). However, the license renewal boundary of these lines, at locations B/C-2 and H-3, is shown to end at valves F026 and F031. It is not clear that the piping no longer has the potential to impact safety-related components beyond valves F026 and F031. The applicant was requested to provide additional information to clarify the extent of the license renewal boundary.

In its response dated June 11, 2012, the applicant stated that the piping and piping components beyond the valves contain air and do not have any potential to affect safety-related components.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-8 acceptable because the lines beyond valves F026 and F031 do not need to be within the scope of license renewal since they contain air and do not have the potential to affect safety-related components. Therefore, the staff's concern described in RAI 2.3.3.19-8 is resolved.

In RAI 2.3.3.19-9, dated May 14, 2012, the staff noted process sampling system license renewal boundary drawing LRA-M-1069B shows 10 sampling lines that are within the scope of license renewal for 10 CFR 54.4(a)(2). However, connected to these 10 piping sections are drip lines that are not shown as within the scope of license renewal. The applicant was requested to provide additional information to clarify the license renewal boundary.

In its response dated June 11, 2012, the applicant stated that the 10 drip lines are within the scope of license renewal for 10 CFR 54.4(a)(2) and are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-9 acceptable because the applicant stated that the 10 drip lines in question are appropriately included within the components subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.19-9 is resolved.

In RAI 2.3.3.19-10, dated May 14, 2012, the staff noted turbine building cooling water system license renewal boundary drawing LRA-M-1044A, location F-6, shows line 1"-JBD-1342 to be within the scope of license renewal for 10 CFR 54.4(a)(2) with a continuation to drawing LRA-M-1062C (location D-1). However, the continuation of this line on drawing LRA-M-1062C is shown as not within the scope of license renewal. The applicant was requested to provide additional information to clarify the scoping classification of this pipe section.

In its response dated June 11, 2012, the applicant stated that the continuation on drawing LRA-M-1062C should have been highlighted as within the scope of license renewal. The affected components subject to an AMR are already captured in the component type "piping" in LRA Table 2.3.3-19-18.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-10 acceptable because the applicant described the correct scoping classification for the piping on drawing LRA-M-1062C and appropriately included the piping within the scope of license renewal, which establishes an acceptable license renewal scoping boundary. Therefore, the staff's concern described in RAI 2.3.3.19-10 is resolved.

2.3.3.19.3 Conclusion

On the basis of its review of the LRA, UFSAR, and RAI responses, the staff concludes the applicant appropriately identified the miscellaneous auxiliary systems in scope for 10 CFR 54.4(a)(2) 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 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, "Condensate and Refueling Water Storage and Transfer"
- 2.3.4.2, "Miscellaneous Steam and Power Conversion Systems in Scope for 10 CFR 54.4(a)(2)"

The staff's findings on the review of LRA Sections 2.3.4.1 – 2.3.4.2 are in SER Sections 2.3.4.1 – 2.3.4.2, respectively.

Steam and Power Conversion Request for Additional Information

In RAI 2.3.4-1, dated May 15, 2012, the staff noted LRA Section 2.1 describes the applicant's scoping methodology, which specifies how systems or components were determined to be included in the scope of license renewal. The staff confirms the inclusion of all components subject to aging management by reviewing the results of the screening of components within the license renewal boundary. For seven license renewal boundary drawing locations, the continuation of piping in scope for license renewal could not be located. The applicant was requested to provide sufficient information to locate these seven license renewal boundaries. If the continuation cannot be shown on license renewal boundary drawings, then the applicant was requested to provide additional information describing the extent of the scoping boundary and if there are additional AMR component types between the continuation and the termination of the scoping boundary. If the scoping classification of a section of the piping changes over the continuation, the applicant was requested to provide additional information to clarify the change in scoping classification.

In its response dated June 11, 2012, the applicant provided information to clarify the extent of the license renewal boundary for each of the seven continuations. In each case, the applicant detailed the routing and location of the piping in question and stated there were no additional component types subject to an AMR or scoping classification changes.

Based on its review, the staff finds the applicant's response to RAI 2.3.4-1 acceptable because the applicant provided sufficient information to clarify the extent of the license renewal boundary for each of the seven continuations and stated there were no additional component types subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.19-10 is resolved.

2.3.4.1 Condensate and Refueling Water Storage and Transfer

2.3.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the condensate refueling water storage and transfer, and the remote shutdown systems. The LRA states that the purpose of the condensate and refueling water storage and transfer system is to pump and store condensate for the RCIC and HPCS systems; maintain the level of condensate in the condenser hotwell; provide condensate to other plant systems, where required; and handle water during refueling and fuel shipping cask loading operations. The system includes the condensate storage and transfer subsystem and the refueling water storage and transfer subsystem. The purpose of the remote shutdown system is to provide the necessary controls and instrumentation for reactor systems and secondary support systems to shut down the reactor from outside the main control room.

The LRA states that the condensate refueling water storage and transfer system has the intended functions to support automatic transfer of HPCS and RCIC pump suction to the suppression pool on low CST level and to support the containment pressure boundary. The condensate refueling water storage and transfer system also has an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Additionally, the condensate refueling water storage and transfer system has intended functions that demonstrate compliance with the NRC’s regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63).

LRA Table 2.3.4-1 identifies the condensate and refueling water storage and transfer system component types that are 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, UFSAR Sections 7.4.1.4, 7.4.1.5, 9.2.6, 9.5.1, and Appendix 8A, 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 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 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 2.3.4.1-1, dated May 15, 2012, the staff noted LRA Section 2.1.2.1 states that nonsafety-related SSCs attached to safety-related SSCs are within the scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety-related/nonsafety interface. In two instances, the staff could not locate seismic anchors on the nonsafety-related lines. The applicant was requested to provide additional information to locate these two seismic anchors between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response dated June 11, 2012, the applicant described the location of the two seismic anchors.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.1-1 acceptable because the applicant described the location of the two seismic anchors, which are at acceptable locations between the safety-related/nonsafety-related interface and the end of the 10 CFR 54.4(a)(2) scoping boundary. Therefore, the staff's concern described in RAI 2.3.4.1-1 is resolved.

In RAI 2.3.4.1-2, dated May 15, 2012, the staff noted license renewal boundary drawing LRA-M-1065, locations B-6 and C-6, shows expansion joint XJ-G521 to be within the scope of license renewal. However, similar expansion joints (XJ-G522) at location E-5 are shown as not within the scope of license renewal, and noted as "not long-lived." The applicant was requested to provide additional information to clarify the difference in scoping classification.

In its response dated June 11, 2012, the applicant stated that all the expansion joints (XJ-521 and XJ-522) are not subject to an AMR as they are "not long-lived" and are periodically replaced and XJ-G521 should not have been highlighted. The applicant updated LRA Table 3.4.2-2-19 to exclude the component type "Expansion Joint" with material "Elastomer."

Based on its review, the staff finds the applicant's response to RAI 2.3.4.1-2 acceptable because the applicant explained the difference in the scoping classification of the expansion joints. The expansion joints in question are periodically replaced and therefore not a long-lived component subject to AMRs. The applicant has updated LRA Table 3.4.2-2-19 to exclude the expansion joints from AMR. Therefore, the staff's concern described in RAI 2.3.4.1-2 is resolved.

2.3.4.1.3 Conclusion

On the basis of its review of the LRA, UFSAR, and RAI responses, the staff concludes that the applicant appropriately identified the plant service water system components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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).

2.3.4.2 Miscellaneous Steam and Power Conversion Systems in Scope for 10 CFR 54.4(a)(2)

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes steam and power conversion systems that are within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(2) for physical interactions. The condensate and refueling water storage and transfer system is described in LRA Section 2.3.4.1.

The LRA describes the following additional systems that are within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(2) for physical interactions:

- FW control
- main and reheat stem
- condensate and FW
- condensate cleanup
- heater vents and drains
- main turbine and auxiliaries

- main and reactor feed pump turbine seal steam and drain
- lube oil
- moisture separator-reheater vents and drains
- extraction steam
- turbine bypass
- generator
- seal oil
- generator primary water
- excitation
- condenser air removal
- low temperature offgas
- CW

The LRA states that these systems have an intended function to maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Sections 1.2.2.5.9, 7.2.1.1, 7.3.1.1, 7.7.2.4, 10.2, 10.2.2.2, 10.3, 10.4, 10.4.2, 10.4.3, 10.4.4, 10.4.5, 10.4.6, 10.4.7, 10.4.7.2, and 11.3, 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 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 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 2.3.4.2-1, dated May 15, 2012, the staff noted 16 instances on license renewal boundary drawings showing piping "to & from turbine bldg. cooling water system" and vent piping as not within scope of license renewal. However, these piping sections are shown on license renewal boundary drawing LRA-M-1062B as within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to clarify the scoping classification of these pipe sections.

In its response dated June 11, 2012, the applicant stated for these 16 instances the piping and components in question are highlighted on the primary system drawings and are in scope for license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-1 acceptable because the components in question are highlighted as in scope on other primary drawings. Therefore, the staff's concern described in RAI 2.3.4.2-1 is resolved.

In RAI 2.3.4.2-2, dated May 15, 2012, the staff noted condensate and FW system license renewal boundary drawing LRA-M-1053E, locations F-4, F-6, and F-8, shows 1/2"-GBD-188, 1/2"-GBD-187, and 1/2"-GBD-186, "oxygen flow control rack," piping to the condensate system as not within the scope of license renewal. However, the piping is connected to in-scope piping without a separation (i.e., valve). The applicant was requested to provide additional information to justify the scoping classification of these pipe sections.

In its response dated June 11, 2012, the applicant stated these lines are in scope up to the first isolation valve and should have been highlighted on the drawing. Piping upstream of the isolation valve is not fluid filled and therefore not in scope for 10 CFR 54.4(a)(2). Affected components subject to AMR are captured under the component types “piping” and “valve body” in LRA Table 2.3.4-2-3.

Based on its review, the staff finds the applicant’s response to RAI 2.3.4.2-2 acceptable because the applicant clarified the extent of the license renewal boundary and included the additional piping in the scope of license renewal. Therefore, the staff’s concern described in RAI 2.3.4.2-2 is resolved.

In RAI 2.3.4.2-3, dated May 15, 2012, the staff noted CW system license renewal boundary drawing LRA-M-1059B, locations B-3 and B-4, shows injection nozzles of the condenser tube cleaning system “A” and “B” as within the scope of license renewal. LRA Table 2.3.4-2-18 does not list these injection nozzles. The applicant was requested to provide additional information to justify the exclusion of an injection nozzle component type from LRA Table 2.3.4-2-18.

In its response dated June 11, 2012, the applicant stated the injection nozzles are inside the 10 CFR 54.4(a)(2) piping and their failure would not cause spray or leakage onto safety-related equipment. Therefore, the nozzles are not subject to an AMR.

Based on its review, the staff finds the applicant’s response to RAI 2.3.4.2-3 acceptable because the nozzles are inside nonsafety-related piping, cannot impact safety-related equipment, and are therefore not subject to an AMR. Therefore, the staff’s concern described in RAI 2.3.4.2-3 is resolved.

In RAI 2.3.4.2-4, dated May 15, 2012, the staff noted main and reheat steam system license renewal boundary drawing LRA-M-1051A, locations C-3 and C-4, shows two 48-inch lines to the low pressure turbines A and C from the moisture separator reheaters as not within the scope of license renewal. However, the 48-inch line to the low pressure turbine B from the moisture separator reheater is shown as within the scope of license renewal for 10 CFR 54.4(a)(2). Additionally, moisture separator reheater vents and drains system license renewal boundary drawings LRA-M-1056A & B, locations G-4 & G-5, show 1-inch vent piping to the moisture separator reheater hot reheat line as not within scope of license renewal. However, these lines are connected to the moisture separator reheaters, which are in scope for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to justify the scoping classification of these pipe sections.

In its response dated June 11, 2012, the applicant stated these piping and piping components are part of the moisture separator reheater and low pressure turbines pressure boundary and are in scope for 10 CFR 54.4(a)(2), are subject to an AMR, and should have been highlighted from the low pressure turbines to the moisture separator reheaters.

Based on its review, the staff finds the applicant’s response to RAI 2.3.4.2-4 acceptable because the applicant clarified that these piping and piping components are in scope for 10 CFR 54.4(a)(2), are subject to an AMR, and should have been highlighted on the LRA drawings. Therefore, the staff’s concern described in RAI 2.3.4.2-4 is resolved.

In RAI 2.3.4.2-5, dated May 15, 2012, the staff noted main and reheat steam system license renewal boundary drawing LRA-M-1051D, location F-7, shows 6"-HBD-1145 piping from the 2nd stage reheater “B” excess steam bypass to the moisture separator/reheater as not within the scope of license renewal. However, on license renewal boundary drawing LRA-M-1056B, location G-8, this pipe is shown as within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to clarify the scoping classification of this pipe section.

In its response dated June 11, 2012, the applicant stated this piping, as part of the main and reheat steam system excess steam bypass, is in scope for 10 CFR 54.4(a)(2) and is subject to AMR.

Based on its review, the staff finds the applicant’s response to RAI 2.3.4.2-5 acceptable because the applicant clarified that the piping is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Therefore, the staff’s concern described in RAI 2.3.4.2-5 is resolved.

In RAI 2.3.4.2-6, dated May 15, 2012, the staff noted lube oil system license renewal boundary drawing LRA-M-1066D was included in the drawing package but is not included in the table of license renewal boundary drawings in LRA Section 2.3.4.2. The applicant was requested to clarify why license renewal boundary drawing LRA-M-1066D is not included in the list of drawings associated with the lube oil system.

In its response dated June 11, 2012, the applicant corrected LRA Section 2.3.4.2 to include LRA-M-1066D in the listing of license renewal drawings.

Based on its review, the staff finds the applicant’s response to RAI 2.3.4.2-6 acceptable because the applicant corrected the discrepancy in the scoping boundary and included the missing drawing in the revised listing of license renewal drawings associated with the lube oil system. Therefore, the staff’s concern described in RAI 2.3.4.2-6 is resolved.

In RAI 2.3.4.2-7, dated May 15, 2012, the staff noted seal oil system license renewal boundary drawings LRA-M-1116A and B show details for miscellaneous vents and drains for turbine generator equipment. However, there are inconsistencies between the information presented in drawing LRA-M-1116A, Table 1, and the highlighted detail drawings for valves and piping in scope for 10 CFR 54.4(a)(2). For example, valve NIN44F119 is highlighted in scope on LRA-M-1116A, Table 1, but it is not highlighted in the connection M52 drawing or the associated detail drawing. Another example is the 3/4"-HC0-410 that is shown as within the scope of license renewal in the connection M38 drawing and drawing LRA-M-1116A, detail 5, but it is shown as not within the scope of license renewal in LRA-M-1116A, Table 1. The applicant was requested to provide additional information to clarify the discrepancies between the scoping boundaries shown in LRA-M-1116A, Table 1, and the connection and detail drawings.

In its response dated June 11, 2012, the applicant stated valve NIN44F119 is in scope for 10 CFR 54.4(a)(2) and should have been highlighted on the “connection M52” detail. Line 3/4"-HCD-410 is also within scope for 10 CFR 54.4(a)(2). Tables on LRA drawings are used to show valves that are subject to an AMR, but not piping lines. The applicant also stated that the review associated with this RAI response confirmed that no additional component types were subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-7 acceptable because the applicant stated that valve NIN44F119 and line 3/4"-HCD-410 are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The applicant also explained that Table 1 is used to show valves that are subject to an AMR but not piping lines. The applicant also confirmed there were no additional component types subject to an AMR. Therefore, the staff's concern described in RAI 2.3.4.2-7 is resolved.

In RAI 2.3.4.2-8, dated May 15, 2012, the staff noted seal oil system license renewal boundary drawing LRA-M-1116B, location G-8, shows the detail for connection M51 as within the scope of license renewal for 10 CFR 54.4(a)(2). However, drawing LRA-M-1116A, Table 1, does not have any information on connection M51. The applicant was requested to provide additional information to clarify the scoping classification for connection M51.

In its response dated June 11, 2012, the applicant stated that connection M51 is within the scope of license renewal for 10 CFR 54.4(a)(2) and subject to an AMR and that LRA-M1116B, location G-B, shows the detail for connection M51 as within the scope of license renewal for 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-8 acceptable because the applicant confirmed that connection M51 is within the scope of license renewal for 10 CFR 54.4(a)(2) and adequately explained the apparent discrepancy. Therefore, the staff's concern described in RAI 2.3.4.2-8 is resolved.

In RAI 2.3.4.2-9, dated May 15, 2012, the staff noted generator primary water system license renewal boundary drawing LRA-M-1044A, location G-6, shows "Cooler B003" as not within the scope of license renewal. However lines 1"-JBD-1341 and 1"-JBD-1342 run through the cooler and are within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to clarify why cooler B003 is not shown as within the scope of license renewal.

In its response dated June 11, 2012, the applicant stated that the tube side of cooler B003 is liquid filled and the shell side is gas filled. Leakage or spray from the tubes within the cooler boundary will not affect any safety-related components; therefore, the tubes within the cooler are not in the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-9 acceptable because the applicant clarified the scoping boundary and the shell side of cooler B003 does not need to be within the scope of license renewal since it is gas filled and leakage or spray from the liquid filled tubes within the cooler will not affect any safety-related components and. Therefore, the staff's concern described in RAI 2.3.4.2-9 is resolved.

In RAI 2.3.4.2-10, dated May 15, 2012, the staff noted generator primary water system license renewal boundary drawing LRA-M-1044A, locations F-1 and E-6, show traps D035 and D037 as within the scope of license renewal. LRA Table 2.3.4-2-14 does not list traps as a component type subject to an AMR. The applicant was requested to provide additional information to justify the exclusion of a trap component type from Table 2.3.4-2-14.

In its response dated June 11, 2012, the applicant stated that the components were inadvertently omitted from the LRA and revised LRA Tables 2.3.4-2-14 and 3.4.2-2-14 to include the component type "Trap."

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-10 acceptable because the applicant corrected the discrepancy in the scoping boundary and added the component type "Trap" to LRA Tables 2.3.4-2--14 and 3.4.2-2-14. Therefore, the staff's concern described in RAI 2.3.4.2-10 is resolved.

In RAI 2.3.4.2-11, dated May 15, 2012, the staff noted main turbine and auxiliaries system license renewal boundary drawing LRA-M-1117A, locations D-3 and D-4, show valves PV F505A and PV 505B with associated piping as not within the scope of license renewal. However, these valves are shown on drawing LRA-M-1057A, location H-4, as within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to clarify the scoping classification of these pipe sections.

In its response dated June 11, 2012, the applicant stated the "dashed" lines used on LRA-M-1117A indicate these components are shown on another drawing, in this case LRA-M-1057A. LRA-M-1057A shows these components are in the scope of license renewal for 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-11 acceptable because applicant explained the apparent discrepancy and the dashed lines indicate these components are shown on another drawing and the piping in question is in the scope of license renewal for 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.2-11 is resolved.

In RAI 2.3.4.2-12, dated May 15, 2012, the staff noted main turbine and auxiliaries' system license renewal boundary drawing LRA-M-1117A, location A-2, shows the "control fluid purifier skid" as not within the scope of license renewal. However, the lines connecting to this skid are within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to justify the exclusion of the "control fluid purifier skid" from the scope of license renewal.

In its response dated June 11, 2012, the applicant stated that the skid was inadvertently not highlighted on LRA-M-1117A. The component types for this system are included in LRA Table 2.3.4-2-6, Main Turbine and Auxiliaries, and are included in the aging management evaluation in LRA Table 3.4.2-2-6.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-12 acceptable because the applicant clarified the discrepancy in the scoping boundary and the skid has been included in the scope of license renewal and the component types for this system are included in LRA Table 2.3.4-2-6. Therefore, the staff's concern described in RAI 2.3.4.2-12 is resolved.

2.3.4.2.3 Conclusion

On the basis of its review of the LRA, UFSAR, and RAI responses, the staff concludes the applicant appropriately identified the miscellaneous steam and power conversion systems in scope for 10 CFR 54.4(a)(2) 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:

- containment building
- water control structures
- turbine building, process facilities, and yard structures
- bulk commodities

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 SCs 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 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 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 (1) the functions are performed with moving parts or a change in configuration or properties or (2) 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 Containment Building

2.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1, the applicant described the Mark III containment structure as both a biological shield and a pressure container during a loss-of-coolant accident or steam line break accident. The containment structure, as well as all penetrations and the interior structures, are seismic Category I structures.

2.4.1.1.1 Containment

The containment building consists of a foundation mat, right circular cylinder, and a hemispherical dome. The cylindrical wall, dome, and foundation mat are constructed of reinforced concrete. The wall, dome, and associated internal structures are founded on the mat foundation. The applicant stated that the containment also provides support for the RPV support pedestal. The pedestal is rigidly connected to the reinforced concrete base mat. The outside face of the mat is covered with a stainless steel clad, carbon steel liner plate, which also serves as the lower extension of the weir wall, forming the interior boundary of the suppression pool directly opposite the suppression pool vents.

2.4.1.1.2 Enclosure Building

The enclosure building completely encloses the portions of the containment above the auxiliary building roof levels. A flexible seal around the periphery of the enclosure and auxiliary building interface maintains leakage limits. The applicant also stated that the enclosure building is a steel framed, seismic Category I structure with uninsulated metal siding and an insulated roof deck. The building is designed so that most of the siding can become detached during high tornado winds, which completely vents the building; however, the main structural framing is designed to remain in place. The building is founded on the dome and wall of the containment and is anchored to steel-embedded plates and concrete piers. Struts founded on the containment shell support the structural steel frame and an internal inspection platform allows access around the periphery of the building.

2.4.1.1.3 Drywell

The drywell is a reinforced concrete structure with a concrete foundation common to the containment foundation. Its cylindrical walls are subdivided into two structural components, a lower wall and an upper wall. The lower wall has two stiffened steel surface plates penetrated by steel vents. The annulus between the surface plates is concrete; the lower portion is supported by and anchored to the containment base slab. The applicant stated that the lower steel portion also is integrally connected with the upper wall. The upper wall is a reinforced concrete cylinder supported by the steel of the lower wall section and its internal concrete. A reinforced concrete roof contains a circular opening for the drywell head. The head, which is part of the drywell pressure retention boundary, is equipped with a pair of horizontal mating flanges. The lower flange is equipped with two compression seals. The drywell head, constructed of stainless steel, is located directly over the RPV. The drywell liner plate, which forms the suppression pool walls, is a stainless-steel-clad carbon steel plate.

2.4.1.1.4 Suppression Pool and Weir Wall

The suppression pool serves as a heat sink during normal operational transients and accident conditions. The suppression pool area of the containment liner is stainless steel and serves as the fission product barrier. A reinforced concrete slab cantilevered over the suppression pool provides support for the traversing in-core probe station. This reinforced concrete slab has a steel box structure that projects beneath the slab into the suppression pool. The applicant also stated that the weir wall is a vertical, reinforced concrete, right circular cylinder fixed at the bottom and free at the top. The outside face of the wall is covered with a stainless-steel-clad carbon steel liner plate, which forms the inner boundary of the suppression pool. The weir wall supports the steel floor framing at El 114 feet, 6 inches, pipe supports and pipe restraints, and provides missile protection during a DBE.

2.4.1.1.5 Refueling and Reactor Servicing Areas

The refueling pool, located on and integrally attached to the drywell roof, consists of reinforced concrete walls and floors. The outer walls of the drywell form the boundary of the refueling pool. Three interior cross walls form four smaller compartments that subdivide this large pool. The interior face of the pool is lined with a stainless steel liner plate. A horizontal transfer tube penetration at one end of the pool allows transfer for fuel elements between the containment and the auxiliary building.

The applicant stated that the containment building is supplied with a refueling platform for fuel movement and servicing, an auxiliary platform for servicing operations from the refueling floor level, and a vessel platform for reactor servicing from the vessel flange level. These components perform the following functions:

- The refueling platform is a gantry crane used to transport fuel and reactor components to and from pool storage and the RV. The platform spans the fuel storage and vessel pools on bedded tracks in the refueling floor. A telescoping mast and grapple, suspended from a trolley system, lifts and orients fuel bundles for core, storage rack, and upender placement.
- The auxiliary platform operates over the upper containment pools and provides an additional work area for reactor servicing. A hoist is provided for reactor servicing tasks. Part of the auxiliary platform is used as the vessel flange level service platform.
- The reactor level servicing platform provides a reactor flange level working surface for in-vessel inspection and reactor internals servicing and permits servicing access for the full vessel diameter.

The applicant further stated that the containment building serves the following intended functions under 10 CFR 54.4(a)(1), (a)(2), and (a)(3):

- provide shelter, support, and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal. The containment building houses equipment credited in Appendix R, safe shutdown analysis and for fire protection (10 CFR 50.48) for SBO (10 CFR 50.63) and for anticipated transients without scram (10 CFR 50.62)
- provide radiation-shielding barriers to offsite radiation exposure
- provide structural support to limit the release of radioactive materials so that offsite doses from a postulated DBA are below the guideline values of 10 CFR Part 100, “Reactor Site Criteria”
- provide structural support to limit the release of radioactive materials so that offsite doses from a postulated refueling accident fall below the guideline values of 10 CFR 50.67, “Accident Source Term”
- provide a heat sink during normal operational transients and accident conditions (suppression pool)
- maintain the integrity of nonsafety-related structural components so they do not affect safety functions

The applicant also stated that the structural commodities support or protect plant equipment, including system components, piping, and electrical conductors. Structural commodities unique to the containment building are included in this review. Those that are common to inscope systems and structures (e.g., anchors, embedments, pipe and equipment supports, instrument panels and racks, cable trays, and conduits) are reviewed in Section 2.4.4, "Bulk Commodities."

LRA Table 2.4-1 identifies the components subject to an AMR for the containment building by component type and intended function.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 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 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).

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 containment building 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 Water Control Structures

2.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2, the applicant stated that the water control structures reviewed in this section are the SSW cooling towers and Culvert No. 1 and its drainage channel.

2.4.2.1.1 Standby Service Water Cooling Towers

The applicant stated that the ultimate heat sink is comprised of two separate seismic Category I mechanical draft cooling tower, pump house, and basin structures. Each tower consists of four cells, and each cell has a separate stack. Only four cells are required to support operation.

The applicant also stated that the cooling tower basins are the supply source to the SSW system and do not perform any other function. The two SSW cooling towers, pump house, and basin structures are located northwest of the containment building. The structure-supporting components and general construction are described below:

- A makeup water storage basin consists of a reinforced concrete base slab, exterior walls, interior walls and columns to support the cooling tower, a reinforced concrete cover slab, a pump house, and a valve room. The SSW cooling tower basins, which support the cooling towers, are supported on reinforced concrete base mats and founded on the Catahoula Formation

- A pump house supported on the basin roof slab houses the SSW and HPCS pumps (Pump House A) or one SSW pump (Pump House B) and related equipment and piping. The pump house consists of a concrete operating floor slab and exterior walls and roof to protect the seismic Category I equipment from tornado winds and missiles. To prevent debris from entering the piping system, a platform with a perforated plate covers the sump area from which the SSW and HPCS service water pumps take suction
- A pipe and valve room consists of a reinforced concrete enclosure structure above the basin cover slab to protect the seismic Category I piping and valves from tornado winds and missiles
- The mechanical draft SSW cooling towers supported by the basin columns and interior walls consist of concrete exterior walls, interior walls, columns and beams, a roof slab, and four concrete fan stacks with steel grating over each fan stack top to protect the fans from tornado-entrained debris. The stacks are designed to provide full horizontal missile protection for the fans. The towers are provided with air intake louvers in the side wall and contain fill within the frame structure

The applicant further stated that the two structures have the following intended functions covered under 10 CFR 54.4(a)(1), (a)(2), or (a)(3):

- provide a flow path for cooling water from safety-related and nonsafety-related cooling water systems
- maintain integrity of nonsafety-related structural components so they do not affect safety functions
- maintain ultimate heat sink
- provide support, shelter, and protection for equipment covered under Appendix R safe shutdown capability analysis and provisions for fire protection (10 CFR 50.48)

2.4.2.1.2 Culvert No. 1 and Drainage Channel

The applicant stated that Culvert No. 1 is located at the downstream end of the channel draining area designated as Basin B. The applicant also stated that Culvert No. 1 is a corrugated metal pipe culvert with a reinforced concrete headwall at the point of entry. The drainage channel consists of a reinforced concrete slab with soil and riprap slopes. The applicant stated that Culvert No. 1 and the drainage channel have the following intended function for 10 CFR 54.4(a)(2): maintain integrity of nonsafety-related structural components so they do not affect safety functions.

The applicant further stated that structural commodities support or protect plant equipment, including system components, piping, and electrical conductors. Structural commodities that are unique to the water control structures are included in this review. Those that are common to inscope systems and structures (e.g., anchors, embedments, equipment supports, instrument panels, racks, cable trays, and conduits) are reviewed in Section 2.4.4.

LRA Table 2.4-2 identifies the components subject to an AMR for the water control structures by component type and intended function.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 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 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).

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 water control structures 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 Turbine Building, Process Facilities and Yard Structures

2.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3, the applicant stated that the turbine building, process facilities, and yard structures consisted of the following:

- turbine building
- process facilities
  - auxiliary building
  - control building
  - diesel generator building
  - radioactive waste building
- yard structures
  - CST foundation
  - condensate storage and refueling water storage tank (RWST) retaining basin
  - containment building (GGN2)
  - control house—switchyard
  - diesel generator fuel oil storage tanks access tunnel
  - fire water pump house and storage tanks foundation
  - manholes and duct banks
  - radioactive waste building pipe tunnels
  - RWST foundation
  - transformer and switchyard support structures and foundations

2.4.3.1.1 Turbine Building

The applicant stated that the turbine building is a non-Category I structure located adjacent to seismic Category I structures. The building is constructed of reinforced concrete and structural steel with metal roof decking. The interior walls are concrete and concrete block construction.

The turbine building houses safety-related instruments, but the building, including the foundation, is designed to seismic Category I requirements able to withstand tornado-force winds (except the siding and its supporting members) and will have no adverse effects on the adjacent Category I structures.

The turbine building has the following intended functions under 10 CFR 54.4(a)(1), (a)(2), and (a)(3):

- provide structural support to safety-related equipment
- maintain integrity of nonsafety-related structural components so they do not affect safety functions
- provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal

2.4.3.1.2 Process Facilities

Auxiliary Building. The applicant stated that the auxiliary building is a seismic Category I structure that completely encircles the containment from base mat to mid-height. The applicant also stated that the auxiliary building is constructed of reinforced concrete, structural steel, and supported on a reinforced concrete base mat on structural fill. The building is a multilevel structure with floor slabs, reinforced concrete walls, structural steel columns, and composite columns supported by the concrete foundation. Reinforced concrete block walls make up portions of the internal structure. The applicant further stated that the floor and roof systems are of composite construction, using structural steel framework and reinforced concrete slabs. A horizontal waterstop is provided between the control, turbine, and containment foundations and the auxiliary building foundation. Vertical waterstops are placed in the walls at various locations to provide watertightness.

This structure has the following intended functions under 10 CFR 54.4(a)(1), (a)(2), or (a)(3):

- provide shelter, support, and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal. The auxiliary building houses equipment covered in the Appendix R safe shutdown analysis, provisions for fire protection covered in 10 CFR 50.48, and provisions for SBO, as specified in 10 CFR 50.63.
- provide radiation-shielding barriers to offsite radiation exposure
- provide missile protection for the portion of the RCPB, located in the auxiliary building steam tunnel
- maintain integrity of nonsafety-related structural components so they do not affect safety functions

Control Building. The applicant stated that the control building is located adjacent to the turbine and auxiliary buildings and houses the main control room, upper cable spreading room, safeguard switchgear, and battery rooms. The applicant also stated that the building is a multilevel reinforced concrete and steel structure. The structure is composed of composite sections of concrete slabs resting on steel beams. The control building's foundation is a reinforced concrete base mat founded on the Catahoula Formation. The mat is physically separated from adjoining buildings by compressible material to prevent seismic interaction.

The applicant further stated that the structure has the following intended functions as covered under 10 CFR 54.4(a)(1), (a)(2), and (a)(3):

- provide functional support as a habitable environment for the operators in the control room post-accident
- provide radiation and missile shielding protection
- provide support, shelter, and protection for control room building components under the Appendix R safe shutdown capability analysis (10 CFR 50.48) and for SBO (10 CFR 50.63)
- maintain integrity of nonsafety-related components so they do not affect safety functions

Diesel Generator Building. The applicant stated that the diesel generator building is a seismic Category I structure that provides shelter and protection to the emergency diesel generators. The applicant also stated that the building is a three-celled (one for each generator), one-story concrete structure supported by a reinforced concrete base slab founded on structural backfill. The base mat is separated from the auxiliary building by compressible material to prevent seismic interaction. The diesel generators rest upon individual concrete foundations, separated from the building foundation.

The applicant further stated that the diesel generator building has the following intended functions under 10 CFR 54.4(a)(1), (a)(2), and (a)(3):

- provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal. The diesel generator building houses equipment (emergency diesel generators) covered under the Appendix R safe shutdown analysis and provisions for fire protection (10 CFR 50.48)
- maintain integrity of nonsafety-related structural components so they do not affect safety functions

Radioactive Waste Building. The applicant stated that the radioactive waste building is a non-Category I structure designed to comply with Category I requirements to prevent uncontrolled release of radioactivity from waste material to the environment. The applicant also stated that the radwaste building is partially embedded in soil. The building is a multilevel structure with floor slabs, reinforced concrete walls, concrete block walls, and structural steel. The reinforced concrete walls and structural steel columns support the superstructure. The floor and roof systems are of composite construction, using structural steel framework and reinforced concrete slabs. The foundation is a reinforced concrete mat supported on structural fill. Waterstops are provided between the turbine and radwaste building foundation and are placed between the walls of the two buildings to provide watertightness.

The applicant further stated that the radioactive waste building has the following intended function under 10 CFR 54.4 (a)(2): maintain structural integrity if nonsafety-related components such that safety functions are not affected and no impact on in-scope structures.

2.4.3.1.3 Yard Structures

Condensate Storage Tank Foundation. The applicant stated that the CST foundation supports the CST, which provides the required condensate capacity and flow of condensate for the RCIC and HPCS systems and maintains the required level in the condenser hotwell. The applicant also stated that the CST is located adjacent to the RWST and shares a common concrete retaining basin with the RWST. The CST foundation consists of reinforced concrete founded on structural fill.

The applicant further stated that the CST foundation has the following intended functions under 10 CFR 54.4(a)(1), (a)(2), and (a)(3):

- maintain integrity of nonsafety-related structural components so they do not affect safety functions
- provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal. The CST foundation supports CSTs as covered in the Appendix R safe shutdown analysis and provisions for fire protection (10 CFR 50.48) and for SBO (10 CFR 50.63)

Condensate Storage and Refueling Water Storage Tank Retaining Basin. The applicant stated that the CST and RWST retaining basin is integral to the foundation of the CST and RWST. The retaining basin is sized to retain the full capacity of the CST and the RWST to prevent an uncontrolled release of contents. The applicant also stated that the retaining basin is a reinforced concrete structure supported on compacted structural fill.

The applicant further stated that the CST and RWST retaining basin has the following intended function for 10 CFR 54.4(a)(2): Provide support and protection of the CST and RWST.

Containment Building. The applicant stated that the containment building (GGN2), located adjacent to the control building, is partially complete and abandoned in place. It contains no system or components required for plant operations. Even though Unit 2 construction has been abandoned, the partially completed building still remains. The applicant also stated that the partially completed external concrete walls provide missile protection for louvers and other vulnerable openings of the control building against tornado-generated missiles. The structure has no safety function. Its failure will not compromise any safety-related system or component and will not prevent safe reactor shutdown.

The applicant further stated that GGN2 is made of reinforced concrete and is open to the atmosphere above El 243 feet, 6 inches.

The applicant also stated that GGN2 has the following intended functions under 10 CFR 54.4(a)(2):

- maintain integrity of nonsafety-related structural components so they do not affect safety functions
- provide missile protection for portions of the control building's external openings

Control House—Switchyard. The applicant stated that the switchyard control house is a single-story structure in the main switchyard that houses relays associated with the offsite 500 kilovolts (kV) and 115 kV lines. This prefabricated metal building is supported on a reinforced concrete slab foundation. The building is nonseismic and provides protection for equipment required for SBO recovery.

The applicant also stated that the switchyard control house has the following intended function under 10 CFR 54.4 (a)(3): Provide support and shelter for electrical equipment required for SBO recovery.

Diesel Generator Fuel Oil Storage Tanks Access Tunnel. The applicant stated that the diesel generator fuel oil storage tank access tunnel provides access to fuel oil pumps associated with the tanks. Each tank is buried in structural backfill, and a separate shaft constructed from a 6-foot diameter corrugated metal pipe provides access to each pump. A reinforced concrete slab outfitted with a manhole cover protects the access shaft against missiles.

The applicant also stated that the diesel fuel oil storage tanks access tunnel has the following intended functions under 10 CFR 54.4(a)(2) and (a)(3):

- maintain integrity of nonsafety-related structural components so they do not affect safety functions
- provide structural and functional support for safety-related equipment and nonsafety-related equipment within the scope of license renewal. The tunnel provides access to fuel oil tanks, which support equipment (emergency diesel generators) as covered under the Appendix R safe shutdown analysis for fire protection (10 CFR 50.48)

Fire Water Pumphouse and Storage Tanks Foundation. The applicant stated that the fire water pumphouse and storage tanks foundation provide support for the site's fire protection water supply system. The applicant also stated that the fire water pumphouse consists of structural steel with a metal siding exterior and internal walls of concrete block. The pumphouse is supported on a reinforced concrete foundation on compacted granular structural fill. A circular reinforced concrete foundation and compacted granular fill support the tanks.

The applicant also stated that the fire water pumphouse and storage tanks foundation has the following intended function under 10 CFR 54.4(a)(3): Provide support, shelter, and protection for components credited for fire protection (10 CFR 50.48).

Manholes and Duct Banks. The applicant stated that manholes and duct banks exist in the GGNS yard for underground routing of cables and piping. The seismic Category I electrical manholes are located in the yard between the SSW cooling tower and the control building. The applicant also stated that the manholes are reinforced concrete structures buried in structural backfill and fitted with a ductile cast iron manhole cover for access. Duct banks are located below grade in structural backfill and consist of reinforced concrete, which encloses the electrical conduits and provides missile protection.

The applicant further stated that the manholes and duct banks have the following intended functions under 10 CFR 54.4(a)(1), (a)(2), and (a)(3):

- provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal
- maintain integrity of nonsafety-related structural components so they do not affect safety functions
- provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal. Manholes and duct banks house cable covered under the Appendix R safe shutdown analysis (10 CFR 50.48) and provisions for SBO (10 CFR 50.63). Manhole seals are credited for fire protection (10 CFR 50.48)

Radioactive Waste Building Pipe Tunnels. The applicant stated that the radioactive waste building pipe tunnels are underground structures that run from the auxiliary building to the radwaste building. The applicant also stated that the tunnels consist of reinforced concrete walls and a base slab. The tunnel at the outside of the radwaste building has a box shape with a monolithic top cover. The tunnels' base slabs rest on compacted structural fill supported by the Catahoula Formation, and the sides are covered with either compacted backfill or mass concrete. The tunnel sumps are lined with stainless steel plates and the entire system is waterproofed.

The applicant further stated that the radioactive waste building pipe tunnels have the following intended function under 10 CFR 54.4(a)(2): Maintain the integrity of nonsafety-related structural components in such a way that they do not affect safety functions.

Refueling Water Storage Tank Foundation. The applicant stated that the RWST foundation is located adjacent to the CST north of the auxiliary building. It is supported on a reinforced concrete slab on grade integral with the retaining basin. The applicant also stated that the RWST has no safety function. Failure of the tank foundation will not compromise any safety-related system or component and will not prevent safe reactor shutdown. However, since it is integral to the retaining basis, failure of the foundation could compromise the intended functions associated with the retaining basin.

The applicant further stated that the RWST foundation has the following intended function under 10 CFR 54.4(a)(2): Maintain structural integrity of nonsafety-related structural components for the support and protection of the CST and RWST.

Transformer and Switchyard Support Structures and Foundations. The applicant stated that the purpose of the transformer and switchyard support structures and foundations is to provide physical support to the startup and emergency station service transformers and the other transformer and switchyard components in the SBO offsite power recovery path. These support structures include the transformer foundations and foundations for the associated transformer and switchyard breakers, switchyard bus, and fused disconnect.

The applicant also stated that the transformer and switchyard support structures and foundations have the following intended function under 10 CFR 54.4(a)(3): Provide support for equipment credited for SBO (10 CFR 50.63).

The applicant further stated that structural commodities support or protect plant equipment, including system components, piping, and electrical conductors. Structural commodities that are unique to the turbine building, process facilities, and yard structures are included in this review. Those that are common to inscope systems and structures (e.g., anchors, embedments, equipment supports, instrument panels, racks, cable trays, and conduits) are reviewed in Section 2.4.4.

LRA Table 2.4-3 identifies the components subject to an AMR for the turbine building, process facilities, and yard structures by component type and intended function.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 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 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).

The staff also reviewed the following fire protection documents cited in the CLB listed in the GGNS Operating License Condition 41:

- NRC SERs dated August 23, 1991, and September 29, 2006

Based on the documents above, the staff reviewed the GGNS commitment to 10 CFR 50.48 (i.e., approved Fire Protection Program). The review consisted of a point-by-point comparison with Appendix A to BTP Auxiliary Systems Branch 9.5-1, documented in the UFSAR Table 9.5-11.

The staff confirmed that the fire barriers and associated components (beams, columns, floor and roof slabs, interior and exterior walls, fire proofing, fire wraps, fire dampers, fire doors, and fire penetration seals and components [manways, hatches, manhole covers, and hatch covers]) are included in LRA Tables 2.4-3 and 2.4-4 results of scoping and screening of structures, including fire barriers as subject to an AMR. On the basis of the information in the LRA drawings, UFSAR, and CLB documents the staff did not identify any omissions by the applicant in scoping of the fire barriers and components in accordance with 10 CFR 54.4(a).

2.4.3.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the turbine building, process facilities, yard structures, and fire barrier commodities 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).

2.4.4 Bulk Commodities

2.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.4, the applicant stated that the bulk commodities subject to an AMR are structural components or commodities that perform or support intended functions of inscope SSCs. Bulk commodities unique to a specific structure are included in the review for that structure (Sections 2.4.1, 2.4.2, and 2.4.3). Bulk commodities common to inscope SSCs (e.g., anchors, embedments, pipe and equipment supports, instrument panels and racks, cable trays, conduits) are addressed in this section. Seismic Category I and Category II supports also are addressed. Insulation may have the specific intended functions of (1) maintaining local area temperatures within design limits, or (2) maintaining integrity so that falling insulation does not damage safety-related equipment. The applicant also stated that bulk commodities evaluated in this section are designed to support both safety-related and nonsafety-related equipment during normal and accident conditions in the event of external events (e.g., tornadoes, earthquakes, floods, or missiles) and internal events (e.g., LOCA or pipe breaks).

The applicant further stated that bulk commodities support the various intended functions performed by the structures in which they are located. Therefore, it is within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(1), (a)(2), and (a)(3) to include the support and protection for equipment covered in the Appendix R safe shutdown analysis and provisions for fire protection (10 CFR 50.48), for anticipated transients without scram (10 CFR 50.62), and for SBO (10 CFR 50.63).

LRA Table 2.4-4 identifies the components subject to an AMR for the bulk commodities by component type and intended function.

LRA Table 2.4-4 identifies bulk commodities component types that are 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 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 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).

2.4.4.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the bulk commodities 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 and Instrumentation and Control Systems

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

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 information in the LRA 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 RAI 2.5-1 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 applicant 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 (1) the functions are performed with moving parts or a change in configuration or properties or (2) 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 Control Systems

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 plant electrical and I&C systems including components in the recovery path for loss of off-site power in the event of a SBO. The scoping method includes identifying the electrical and I&C systems and their design functions and reviewing them against criteria contained in 10 CFR 54.4. Those electrical and I&C components that were 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 that are subject to replacement based on a qualified life or specified time period. The following table identifies the component commodity groups that are subject to an AMR and their intended functions:

Component Type	Intended Functions
Cable connections - Metallic Parts	Conducts Electricity
Electrical cables and connections not subject to 10 CFR 50.49 environmental qualifications (EQ) requirements	Conducts Electricity
Electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits	Conducts Electricity
Electrical and I&C penetration cables and connections not subject to 10 CFR 50.49 EQ requirements	Conducts Electricity
Fuse Holders – Insulation Material, Metallic Clamp	Conducts Electricity
Inaccessible Power Cables (400 V to 35 kV) not subject to 10 CFR 50.49 EQ requirements	Conducts Electricity
Inaccessible Power Cables (115 kV) not subject to 10 CFR 50.49 EQ requirements (for SBO recovery)	Conducts Electricity
High-voltage Insulators (for SBO recovery)	Insulation (Electrical)
Switchyard Bus (for SBO recovery) – Bus and Connections	Conducts Electricity

Component Type	Intended Functions
Transmission Conductors and Connections (transmission conductors for SBO recovery)	Conducts Electricity

LRA Table 2.5-1 identifies electrical and I&C system component types that are within the scope of license renewal and subject to an AMR.

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5 and UFSAR Sections 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 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).

General Design Criteria 17 of 10 CFR Part 50, Appendix A, requires that electric power from the transmission network to the onsite electric distribution system 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))," and later incorporated into SRP-LR Section 2.5.2.1.1:

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 SBO requirements are maintained over the period of extended license.

The applicant included the complete circuits between the onsite circuits and up to and including switchyard breakers (including the associated controls and structures) within the scope of license renewal. The scoping boundary consists of the 34.5 kV breakers (552 1104 and 552 2104) and 115 kV breaker (J1365). The 34.5 kV offsite recovery path components consist of the switchyard bus and connections, high-voltage insulators, control circuit cables and connections, medium voltage cables and connections, and inaccessible medium-voltage cables and connections to manholes. The 115 kV offsite recovery path components consist of control circuit cables and connections, high-voltage insulators, overhead transmission conductors and connections, underground 115 kV transmission conductors and connections with manholes, switchyard bus and connections, and medium-voltage cables and connections. Consequently, the staff concludes that the scoping is consistent with the guidance issued in April 1, 2002, and later incorporated into SRP-LR, Section 2.5.2.1.1.

In RAI 2.5-1 dated May 29, 2012, the staff requested the applicant to explain how it manages the aging of cable tie-wraps and justify why they are not included within the scope of license renewal.

In its response dated June 22, 2012, the applicant stated that cable tie-wraps have no license renewal function and are not included as an electrical commodity in the scope of license renewal. The applicant also stated that the cable tie-wraps are used as an aid during cable installation to establish power cable spacing in cable trays and the cable tie-wraps do not function as cable support in raceway support analyses. Furthermore, the applicant is not crediting the use of cable tie-wraps in the seismic qualification of cable trays. Based on the review of this information and the UFSAR, the staff finds the applicant's exclusion of cable tie-wraps from the SSC's subject to an AMR acceptable.

The applicant did not include metal-enclosed bus and uninsulated ground connectors in the commodity groups subject to an AMR because the applicant determined that they do not perform any license renewal functions. The staff reviewed the UFSAR and found that metal enclosed bus and uninsulated ground conductors are not credited in GGNS's design basis. Therefore, the staff concludes that the exclusion of metal enclosed bus and uninsulated ground conductors from the commodity 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 that the applicant appropriately identified the electrical and I&C 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 license 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 section of the safety evaluation report (SER) evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Grand Gulf Nuclear Station, Unit 1 (GGNS), by the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff). In Appendix B of its license renewal application (LRA), Entergy Operations, Inc. (Entergy or the applicant) described the 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 Applicant's Use of the Generic Aging Lessons Learned Report

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, and 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, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54), and consistent with the guidance of NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR) 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 January 23 and January 30, 2012. 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.

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 Number" column and the "Item Number in GALL" column has been replaced by a "Discussion" column. The "Item Number" 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 assumption
- discussion of how the item 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 a 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., reactor coolant system (RCS), engineered safety features (ESF), auxiliary systems). For example, the ESF group has tables specific to the containment spray system, containment isolation system, and emergency core cooling system (ECCS). 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 2.0-1.
- 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.
- Aging Effect Requiring Management – The fifth column lists aging effects requiring management (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.
- Table 1 Item – The eighth column lists the corresponding summary item number 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 eight 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 are based on NEI 95-10, Table 4.2-2. 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 prior to 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 will 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 Program – Scope of 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/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.

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. Item numbers in column seven of the LRA, "NUREG-1801 Item," correlate to an AMR combination as identified in the GALL Report. A blank in column seven 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 the report 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, 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 final safety analysis report (FSAR) 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 and UFSAR 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.

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 the GALL Report AMP. The staff audited these items to verify consistency with the GALL Report and verified that the identified exceptions to the 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 C 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 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 verified whether the AMR item of the different component was applicable to the component under review and whether the identified exceptions to the 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.

3.0.3 Aging Management Programs

SER Table 3.0-1 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 and shows the section of this SER in which the staff's evaluation of the program is documented.

Table 3.0-1 Aging Management Programs

AMP	LRA Section(s)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
115 kV Inaccessible Transmission Cable	B.1.1	New	Plant specific	Plant-specific program	3.0.3.2.1
Aboveground Metallic Tanks	B.1.2	New	Consistent	XI.M29, "Aboveground Metallic Tanks"	3.0.3.1.1
Bolting Integrity	B.1.3	Existing	Consistent with enhancements	XI.M18, "Bolting Integrity"	3.0.3.1.2
Boraflex Monitoring	B.1.4	Existing	Consistent with enhancement	XI.M22, "Boraflex Monitoring"	3.0.3.1.3
Buried Piping and Tanks Inspection	B.1.5	New	Consistent	XI.M41, "Buried and Underground Piping and Tanks"	3.0.3.1.4
BWR CRD Return Line Nozzle	B.1.6	Existing	Consistent with enhancement	XI.M6, "BWR Control Rod Drive Return Line Nozzle"	3.0.3.1.5

AMP	LRA Section(s)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
BWR Feedwater Nozzle	B.1.7	Existing	Consistent	XI.M5, "BWR Feedwater Nozzle"	3.0.3.1.6
BWR Penetrations	B.1.8	Existing	Consistent with enhancement	XI.M8, "BWR Penetrations"	3.0.3.1.7
BWR Stress Corrosion Cracking	B.1.9	Existing	Consistent with exception	XI.M7, "BWR Stress Corrosion Cracking"	3.0.3.1.8
BWR Vessel ID Attachment Welds	B.1.10	Existing	Consistent	XI.M4, "BWR Vessel ID Attachment Welds"	3.0.3.1.9
BWR Vessel Internals	B.1.11	Existing	Consistent with enhancement	XI.M9, "BWR Vessel Internals"	3.0.3.1.10
Compressed Air Monitoring	B.1.12	Existing	Consistent with enhancements	XI.M24, "Compressed Air Monitoring"	3.0.3.1.11
Containment Inservice Inspection – IWE	B.1.13	Existing	Consistent	XI.S1, "ASME Section XI, Subsection IWE"	3.0.3.1.12
Containment Inservice Inspection – IWL	B.1.14	Existing	Consistent	XI.S2, "ASME Section XI, Subsection IWL"	3.0.3.1.13
Containment Leak Rate	B.1.15	Existing	Consistent with exception	XI.S4, "10 CFR 50, Appendix J"	3.0.3.1.14
Diesel Fuel Monitoring	B.1.16	Existing	Consistent with enhancements	XI.M30, "Fuel Oil Chemistry"	3.0.3.1.15
Environmental Qualification (EQ) of Electric Components	B.1.17	Existing	Consistent	X.E1, "Environmental Qualification (EQ) of Electric Components"	3.0.3.1.16
External Surfaces Monitoring	B.1.18	Existing	Consistent with enhancements	XI.M36, "External Surfaces Monitoring of Mechanical Components"	3.0.3.1.17
Fatigue Monitoring	B.1.19	Existing	Consistent with exception and enhancements	X.M1, "Fatigue Monitoring"	3.0.3.1.18
Fire Protection	B.1.20	Existing	Consistent with enhancements	XI.M26, "Fire Protection"	3.0.3.1.19
Fire Water System	B.1.21	Existing	Consistent with enhancements	XI.M27, "Fire Water System"	3.0.3.1.20
Flow-Accelerated Corrosion	B.1.22	Existing	Consistent with exception and enhancement	XI.M17, "Flow-Accelerated Corrosion"	3.0.3.1.21
Inservice Inspection	B.1.23	Existing	Consistent	XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	3.0.3.1.22
Inservice Inspection – IWF	B.1.24	Existing	Consistent with enhancements	XI.S3, "ASME Section XI, Subsection IWF"	3.0.3.1.23
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.1.25	Existing	Consistent with enhancements	XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	3.0.3.1.24
Internal Surfaces in Miscellaneous Piping and Ducting Components	B.1.26	New	Consistent	XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	3.0.3.1.25
Masonry Wall	B.1.27	Existing	Consistent with enhancements	XI.S5, "Masonry Walls"	3.0.3.1.26

AMP	LRA Section(s)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
Non-EQ Cable Connections	B.1.28	New	Consistent	XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.27
Non-EQ Inaccessible Power Cables (400 V to 35 kV)	B.1.29	Existing	Consistent with enhancements	XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.28
Non-EQ Instrumentation Circuits Test Review	B.1.30	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"	3.0.3.1.29
Non-EQ Insulated Cables and Connections	B.1.31	New	Consistent	XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.30
Oil Analysis	B.1.32	Existing	Consistent with enhancements	XI.M39, "Lubricating Oil Analysis"	3.0.3.1.31
One-Time Inspection	B.1.33	New	Consistent	XI.M32, "One-Time Inspection"	3.0.3.1.32
One-Time Inspection – Small-Bore Piping	B.1.34	New	Consistent	XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping"	3.0.3.1.33
Periodic Surveillance and Preventive Maintenance	B.1.35	Existing	Plant specific with enhancements	Plant-specific program	3.0.3.2.2
Protective Coating Monitoring and Maintenance	B.1.36	Existing	Consistent with enhancements	XI.S8, "Protective Coating Monitoring and Maintenance Program"	3.0.3.1.34
Reactor Head Closure Studs	B.1.37	Existing	Consistent with exception	XI.M3, "Reactor Head Closure Stud Bolting"	3.0.3.1.35
Reactor Vessel Surveillance	B.1.38	Existing	Consistent with exception and enhancement	XI.M31, "Reactor Vessel Surveillance"	3.0.3.1.36
RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	B.1.39	Existing	Consistent with enhancements	XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants"	3.0.3.1.37
Selective Leaching	B.1.40	New	Consistent	XI.M33, "Selective Leaching"	3.0.3.1.38
Service Water Integrity	B.1.41	Existing	Consistent with enhancements	XI.M20, "Open-Cycle Cooling Water System"	3.0.3.1.39

AMP	LRA Section(s)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
Structures Monitoring	B.1.42	Existing	Consistent with enhancements	XI.S6, "Structures Monitoring"	3.0.3.1.40
Water Chemistry Control – BWR	B.1.43	Existing	Consistent	XI.M2, "Water Chemistry"	3.0.3.1.41
Water Chemistry Control – Closed Treated Water Systems	B.1.44	Existing	Consistent with enhancements	XI.M21A, "Closed Treated Water System"	3.0.3.1.42

3.0.3.1 AMPs Consistent with the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as consistent, with or without exceptions and/or enhancements, with the GALL Report:

- Aboveground Metallic Tanks
- Bolting Integrity
- Boraflex Monitoring
- Buried Piping and Tanks Inspection
- BWR [Boiling Water Reactor] CRD Return Line Nozzle
- BWR Feedwater [FW] Nozzle
- BWR Penetrations
- BWR Stress Corrosion Cracking
- BWR Vessel ID Attachment Welds
- BWR Vessel Internals
- Compressed Air Monitoring
- Containment Inservice Inspection – IWE
- Containment Inservice Inspection – IWL
- Containment Leak Rate
- Diesel Fuel Monitoring
- Environmental Qualification (EQ) of Electric Components
- External Surfaces Monitoring
- Fatigue Monitoring
- Fire Protection
- Fire Water System
- Flow-Accelerated Corrosion
- Inservice Inspection
- Inservice Inspection–IWF

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Internal Surfaces in Miscellaneous Piping and Ducting Components
- Masonry Wall
- Non-EQ Cable Connections
- Non-EQ Inaccessible Power Cable (400 V to 35 kV)
- Non-EQ Instrumentation Circuits Test Review
- Non-EQ Insulated Cables and Connections
- Oil Analysis
- One-Time Inspection
- One-Time Inspection – Small-Bore Piping
- Protective Coating Monitoring and Maintenance
- Reactor Head Closure Studs
- Reactor Vessel Surveillance
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Selective Leaching
- Service Water Integrity
- Structures Monitoring
- Water Chemistry Control – BWR
- Water Chemistry Control – Closed Treated Water Systems

For AMPs that the applicant claimed are consistent with the GALL Report, with or without exceptions and/or 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 exceptions to the GALL Report to determine whether they are acceptable and adequate. The staff also 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.

3.0.3.1.1 Aboveground Metallic Tanks

Summary of Technical Information in the Application. LRA Section B.1.2 describes the new Aboveground Metallic Tanks Program as consistent with GALL Report AMP XI.M29, "Aboveground Metallic Tanks," as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." The LRA states that the AMP addresses certain indoor and outdoor aboveground metallic tanks constructed on concrete or soil. The aging effects managed by the AMP are loss of material and cracking of both the inside and outside surfaces of the tanks. The LRA states that the AMP will manage these aging effects through periodic visual inspections, thickness measurements of the tank bottoms, and preventive measures such as protective coatings and sealants.

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.M29.

Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02, which revises several GALL Report AMPs including the guidance for AMP XI.M29. Because it was unclear whether the applicant incorporated the updated guidance into its AMPs, by letter dated January 2, 2014, the staff issued RAI 3.0.3-1 requesting that the applicant provide details on how the updated guidance of LR-ISG-2012-02 had been incorporated in its AMPs.

In its response dated May 13, 2014, the applicant revised the Aboveground Metallic Tanks Program to include (a) cracking as an aging effect, (b) the inside surfaces of tanks as areas to be inspected, and (c) certain indoor tanks in the program. The staff finds the applicant's response acceptable because the inclusion of these three items makes the program consistent with the updated guidance in the GALL Report.

Based on its audit of the applicant's Aboveground Metallic Tanks Program and review of the applicant's response to RAI 3.0.3-1, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M29, as modified through LR-ISG-2012-02.

Operating Experience. LRA Section B.1.2 summarizes operating experience related to the Aboveground Metallic Tanks. The applicant stated that a visual inspection of the condensate storage tank (CST) conducted in 2007 found no indications of age-related degradation.

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 staff's "Aging Management Program Audit Report Regarding the Grand Gulf Nuclear Station, Unit 1" (AMP Audit Report), dated June 8, 2012, 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, resulting in the issuance of RAIs, as discussed below.

During the audit, the staff's walkdown of the stainless steel CST revealed extensive rust stains (i.e., encompassing 360 degrees around the tank). These rust stains appeared to originate from the tank roof to shell weld. The applicant could not state the cause of the rust stains on this stainless steel tank. By letter dated April 16, 2012, the staff issued RAI B.1.2-1 requesting that the applicant state the cause of the rust stains on the side of the CST and state the basis for why the cause of the rust stains does not indicate the presence of an aging effect that would require a methodology, other than visual inspections, for managing aging of the tank.

In its response dated May 14, 2012, the applicant stated that based on an engineering evaluation conducted subsequent to a structural maintenance rule walkdown, the rust stains are superficial in that they are the result of initial corrosion of uncoated carbon steel angles installed at the springline of the tank. The carbon steel angles were evaluated for loss of material, cleaned, and coated as a result of the walkdown.

The staff finds the applicant's response acceptable because the stains were a result of carbon steel members corroding before being coated; the carbon steel members were evaluated, cleaned, and coated and therefore further corrosion should not occur, or it would be detected during periodic visual inspections conducted by this program. The staff's concern described in RAI B.1.2-1 is resolved.

Based on the staff's review of plant-specific operating experience related to the fire water storage tanks, there are a considerable number of condition reports documenting inspection findings from 2002, 2006, 2007, 2008, and 2009 identifying rust stains, coating damage and holidays on the bottom of the tanks. In addition, during its audit walkdown, the staff noted several locations on both tanks where the top edge of the sealant between the tank and tank foundation had separated from the tank surface. These gaps could allow water to enter between the tank bottom and foundation. By letter dated April 16, 2012, the staff issued RAI B.1.2-2 requesting that the applicant state the basis for why one volumetric inspection of the tank bottom within 5 years of the period of extended operation and then whenever the tank is drained is sufficient to manage the aging of the fire water storage tanks.

In its response dated May 14, 2012, the applicant stated that:

(a) to date, the tanks have maintained the ability to perform their intended function

(b) if no significant degradation is found during the volumetric examination that occurs no earlier than 35 years, then increasing the number of volumetric examinations would not be warranted

(c) if significant degradation is found, the inspection results and industry operating experience would be used to determine the acceptability of the findings and the need for subsequent inspections

(d) appropriate design specifications will be used to evaluate the findings

(e) the condition of the sealant has been documented in the corrective action program and a work request for refurbishment has been initiated

(f) LRA Sections A.1.2 and B.1.2 have been revised to state that, "[t]anks are inspected externally at least once every refueling cycle. In addition, ultrasonic examination (UT) thickness measurements of the tank bottoms will be performed at least once within the 5 years prior to the period of extended operation and whenever the tanks are drained during the period of extended operation."

The staff finds the applicant's response acceptable because:

(a) to date, the coating damage, holidays and rust stains have not resulted in loss of function of the tanks

(b) design specifications will be used to evaluate the volumetric results

(c) if significant degradation is found, the evaluation will include the need for subsequent volumetric examinations

(d) during the walkdown, the staff noted that the majority of the sealant circumference adhered to the side of the tank and the gaps at the localized defective areas were not large, the condition of the sealant has been documented in the corrective action program, a work request for refurbishment has been initiated, and potential corrosion caused by leakage past the sealant would be detected by the volumetric examination

(e) the program and updated final safety analysis report (UFSAR) supplement were revised to include the external inspections and ultrasonic thickness measurement of the tank bottoms

The staff’s concern described in RAI B.1.2-2 is resolved.

The applicant identified that the CST base seal was leaking in December 2010. The work order to correct this adverse condition is currently not scheduled to be completed until May 2013. Given the span of time during which the tank is susceptible to corrosion due to this leaking seal, it is not clear to the staff that one volumetric inspection of the tank bottom within 5 years of the period of extended operation and then whenever the tank is drained is sufficient to manage the aging of the CST. By letter dated April 16, 2012, the staff issued RAI B.1.2-3 requesting that the applicant state the basis for why one volumetric inspection of the tank bottom within 5 years of the period of extended operation and then whenever the tank is drained is sufficient to manage the aging of the CST.

In its response dated May 14, 2012, the applicant stated that:

(a) to date, the tank has shown no significant degradation and it has maintained its ability to perform its intended function

(b) if no significant degradation is found during the volumetric examination that occurs no earlier than 35 years, then increasing the number of volumetric examinations would not be warranted

(c) if significant degradation is found, the inspection results and industry operating experience would be used to determine the acceptability of the findings and the need for subsequent inspections

(d) appropriate design specifications will be used to evaluate the findings

(e) LRA Sections A.1.2 and B.1.2 have been revised to state that, “[t]anks are inspected externally at least once every refueling cycle. In addition, UT thickness measurements of the tank bottoms will be performed at least once within the 5 years prior to the period of extended operation and whenever the tanks are drained during the period of extended operation”

The staff finds the applicant’s response acceptable because:

(a) design specifications will be used to evaluate the volumetric results

(b) if significant degradation is found, the evaluation will include the need for subsequent volumetric examinations

(c) the program and UFSAR supplement were revised to include the external inspections and ultrasonic thickness measurement of the tank bottoms

(d) the staff noted that, without a volumetric examination, it is not possible to determine if significant degradation due to the leaking tank base seal has occurred; however, the volumetric examination performed within 5 years of entering the period of extended operation will provide a basis for the tank being able to perform its CLB function(s) or demonstrate the need for repairs

The staff’s concern described in RAI B.1.2-3 is resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs B.1.2-1, B.1.2-2, and B.1.2-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.2, as modified by letter dated May 13, 2014, provides the UFSAR supplement for the Aboveground Metallic Tanks Program. In its response dated May 13, 2014, the applicant revised the UFSAR supplement to include (a) surface exams to detect cracking, (b) tank internal visual and surfaces examinations, and (c) the inspection of external surfaces of insulated tanks. An inspection table with accompanying notes was also added that includes inspection techniques, frequency of inspections, and minimum surface area to be examined for the relevant material, environment, aging effect combinations. The applicant only has stainless steel tanks in scope; therefore, stainless steel was the only material considered in the inspection table. The applicant does not have any in-scope indoor tanks; therefore, indoor tanks were not included in the UFSAR supplement.

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, as modified by LR-ISG-2012-02. The staff also noted that the applicant committed (Commitment No. 2) to implement the new Aboveground Metallic Tanks Program prior to entering the period of extended operation for managing aging of applicable components. The staff finds that the information in the UFSAR supplement, as modified by letter dated May 13, 2014, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Aboveground Metallic Tanks 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.M29. 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 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B.1.3 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 preload, cracking, and loss of material for closure bolting for pressure-retaining components using preventive and inspection activities. 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," issued June 1990; Electric Power Research Institute (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 one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M18. For the "preventive actions" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "preventive actions" program element in GALL Report AMP XI.M18 recommends that the program include preventive actions, including the use of bolting material that has an actual measured yield strength limited to less than 150 ksi. The program further states that if used, high-strength closure bolting (actual yield strength greater than or equal to 150 ksi) should be monitored for cracking since it may be subject to stress-corrosion cracking (SCC). During the audit, the staff reviewed the Bolting Integrity Program plant basis document and other supporting documents and interviewed the plant staff and was unable to determine whether or not high-strength closure bolts are in use at the plant. LRA Section B.1.3 states that the program is consistent with GALL Report AMP XI.M18; however, statements the applicant made appear to contradict the information presented in the LRA. By letter dated April 11, 2012, the staff issued RAI B.1.3-1 requesting that the applicant clarify whether high-strength closure bolts are in use at the plant, and provide an explanation of the plant processes or procedures used to identify the high-strength closure bolts.

In its response dated May 9, 2012, the applicant stated that the only high-strength bolting identified at GGNS is the reactor vessel (RV) closure bolting, which is discussed in LRA Section B.1.37. The applicant also stated that the enhancement to the "detection of aging effects" program element for high-strength bolting is included to manage high-strength bolting that may be placed into use in the future and clarified that any potential future use of high-strength bolting is managed through the design change process when component material specifications are reviewed.

The staff finds the applicant's response acceptable because the applicant confirmed that (1) the only high-strength bolting identified at GGNS is the RV closure bolting, which is managed by the Reactor Head Closure Studs or Bolting Integrity Programs, (2) the enhancement to the detection of aging effects program element provides inspection techniques to manage aging in high-strength bolting that may be used in the future, and (3) any future use of high-strength bolts will be identified in the design process. The staff's concern described in RAI B.1.3-1 is resolved.

The staff also reviewed the portions of the "preventive actions" and "detection of aging effects" 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.1.3 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that the Bolting Integrity Program will be enhanced to clarify the prohibition on use of lubricants containing molybdenum disulfide (MoS_2) for bolting and to specify that proper gasket compression will be visually confirmed following assembly. 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. It also states that the use of MoS_2 as a lubricant has been shown to be a potential contributor to SCC and should not be used. GALL Report AMP XI.M18 further states that bolting replacement activities include checking for uniformity of the gasket compression after assembly. 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 2. LRA Section B.1.3 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the Bolting Integrity Program will be enhanced to include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339, EPRI NP-5769, and EPRI TR-104213. GALL Report AMP XI.M18 states that bolting inspections should include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339, EPRI NP-5769, and EPRI TR-104213. During the audit, the staff reviewed the implementing procedures and found that although the recommended guidance documents were not consistently referenced in the implementing procedures, the specific guidance from the recommended guidance documents already had been included and proper actions were already in place. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because it will confirm that the program remains consistent with the recommendations in the GALL Report AMP by ensuring that the proper specifications are used.

Enhancement 3. LRA Section B.1.3 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the Bolting Integrity Program will be enhanced to include volumetric examination per American Society of Mechanical Engineers (ASME) Code Section XI, Table IWB-2500-1, Examination Category B-G-1, for high-strength closure bolting, regardless of code classification. High-strength closure bolting is bolting with actual yield strength greater than or equal to 150 ksi. 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 that high-strength closure bolting (regardless of code classification) should be subjected to volumetric examination in accordance with that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1. 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.

Summary. Based on its audit and review of the applicant’s response to RAI B.1.3-1, the staff finds that program elements one through six 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” and “detection of aging effects” program elements and finds that when implemented, the AMP will be adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.3 summarizes operating experience related to the Bolting Integrity Program. In one operating experience example, the LRA states that during examinations of core spray (CS) sparger bolts in 2005, a tack weld on one bolt was found to be cracked. The tack weld is provided to prevent de-tensioning of the bolt. The remaining configuration, including another tack weld on this bolt, was found to provide an adequate locking mechanism. During the audit, the staff further reviewed this incident, and found that an engineering evaluation had been conducted to determine that the necessary torque was still maintained, and also found that the inspection interval for the bolt was increased to every refueling outage.

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 AMP 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.

GALL Report AMP XI.M18 manages aging of closure bolting for pressure retaining components. The program includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, etc. LRA Section B.1.3 describes an operating experience example in which corrosion was discovered on bolting located in the service water system basin under approximately 5 feet of water. The flange studs, nuts, and portions of the flange were observed to be covered with an iron-colored deposit. When the deposit was removed from the studs and nuts on this flange, most of the protective coating was found to be deteriorated and there was noticeable metal loss from the studs. However, there were no signs of system leakage at this location nor were there any signs of previous leakage. It is not clear to the staff how the corrosion described in the LRA was discovered since it would be difficult to identify loss of preload, cracking, and loss of material for bolting in a submerged environment through system walkdowns and visual indications of leakage, which are the only inspection methods used in the applicant's Bolting Integrity Program. By letter dated April 11, 2012, the staff issued RAI B.1.3-2 requesting that the applicant clarify the inspection technique used to discover the corrosion identified and to describe the frequency of the inspection for this example as well as all other bolting in submerged environments.

In its response dated May 9, 2012, the applicant stated that the operating experience listed in LRA B.1.3 was identified during an underwater visual inspection of A and B standby service water (SSW) basin bolting that is performed by divers at least once every refueling cycle. The applicant also stated that other similar locations were also examined and corrosion was not found. The applicant further stated that visual inspections that will detect cracking and loss of material in bolting is conducted for submerged bolting at least once every refueling cycle.

The staff finds the applicant's response acceptable because (1) underwater inspections performed by divers will be able to detect corrosion such as loss of material and cracking on submerged bolting, and (2) the loss of preload aging effect is primarily managed through the proper selection of bolting material, the use of appropriate lubricants, proper torquing, and uniform gasket compression. However, the applicant will have the opportunity to look for loose or missing nuts and bolts during visual inspections and also identifies it in its AMR tables as items that will be age managed by its Bolting Integrity Program. The staff's concern described in RAI B.1.3-2 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.1.3-2, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.3 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 applicant committed (Commitment No. 3), to enhance the program prior to the period of extended operation to provide guidance to ensure proper specification of bolting material, lubricants and sealants, storage, installation torque or tension; prohibit the use of lubricants containing molybdenum disulfide; and include volumetric examination for high-strength closure bolting regardless of code classification. 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 applicant's Bolting Integrity 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 through Commitment No. 3 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Boraflex Monitoring

Summary of Technical Information in the Application. LRA Section B.1.4 describes the existing Boraflex Monitoring Program as consistent, with enhancement, with GALL Report AMP XI.M22, “Boraflex Monitoring.” In the LRA the applicant stated that the program “manages the change in materials properties (neutron-absorbing capacity) in the Boraflex material affixed to spent fuel racks using silica sampling, areal density testing, and other monitoring activities. Inspection frequency and acceptance criteria are based on the GGNS response to NRC Generic Letter (GL) 96-04, ‘Boraflex Degradation in Spent Fuel Pool Storage Racks’ and the GGNS technical specifications.”

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.M22. 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 RAIs, as discussed below.

The scope of the program element in GALL Report AMP XI.M22 recommends that the scope should be the sheets of neutron-absorbing material made of Boraflex affixed to spent fuel racks. However, during its audit the staff found that the applicant’s Boraflex Monitoring Program was unclear whether the upper containment pool that contains Boraflex was included in the Boraflex Monitoring Program. By letter dated June 22, 2012, the staff issued RAI B.1.4-1a requesting that the applicant clarify whether the upper containment pool was part of the Boraflex Monitoring Program.

In its response dated July 23, 2012, the applicant stated that it is revising the program to include the upper containment pool.

The staff finds the applicant’s response acceptable because it was clarified that the upper containment pool that contains Boraflex will be managed under the Boraflex Monitoring Program. The staff’s concern described in RAI B.1.4-1a is resolved.

The “detection of aging effects” and “monitoring and trending” program elements in GALL Report AMP XI.M22 do not recommend the use of the coupon monitoring technique for aging management of the Boraflex. They do recommend the use of RACKLIFE or its equivalent for monitoring and trending. However, during its audit, the staff found that the applicant’s Boraflex Monitoring Program still uses the coupon monitoring technique and was not clear about the frequency at which RACKLIFE predictions would be performed. By letter dated June 22, 2012, the staff issued RAI B.1.4b and c requesting that the applicant clarify whether the applicant would still perform the coupon monitoring technique in the period of extended operation and clarify the frequency at which RACKLIFE is being performed.

In its response dated July 23, 2012, the applicant stated that it would not be relying on the coupon monitoring technique in the period of extended operation. In the period of extended operation, the applicant will be relying on the RACKLIFE predictions and BADGER testing for the Boraflex Monitoring Program. In addition, the applicant would also be performing and updating the RACKLIFE model every cycle. The applicant also states that "Updating the RACKLIFE model once each cycle is sufficient as the Boraflex degradation is a slowly varying, long-term process."

The staff finds the applicant's response acceptable because it is not relying on the coupon monitoring technique in the period of extended operation and will be relying on the RACKLIFE model and BADGER testing. Since the RACKLIFE model will be performed and updated every cycle, this provides the staff with reasonable assurance that the degradation of Boraflex will be monitored for degradation in the period of extended operation. Although the staff does not agree with the applicant's assertion that Boraflex degradation is always slow, the staff recognizes that with the frequencies proposed by the applicant, the degradation will be able to be monitored in the period of extended operation. The staff's concern described in RAI B.1.4-1b and c is resolved.

The staff also reviewed the portions of the "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</u>. LRA Section B.1.4 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 BADGER testing on the Boraflex material will be performed at least once every 5 years, RACKLIFE will be performed every cycle, the plant silica data results would be compared to the RACKLIFE predicted silica values, and there will be projections of the degradation until the next RACKLIFE analysis is performed to ensure that the storage locations do not need to be reclassified. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M22 and finds it acceptable because when it is implemented it will provide reasonable assurance that the BADGER testing and RACKLIFE model will be performed on a frequency consistent with the GALL Report and that the applicant will be predicting the degradation between surveillance intervals to ensure that the Boraflex will be able to perform its intended function.

Based on its audit of the applicant's Boraflex Monitoring Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M22. In addition, the staff reviewed the enhancement and finds that when implemented, it will make the AMP adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B.1.4 summarizes operating experience related to the Boraflex Monitoring Program. The applicant stated:

> [t]he results of spent fuel storage pool neutron transmission testing in 1999 revealed boraflex gaps in the test area exceeding those assumed in the criticality safety analysis. Engineering disposition of these results was used to prohibit storage of any fuel in the spent fuel pool boraflex test area.

In-situ measurement of the boron-10 areal density of the neutron absorber material in 2007 identified no immediate actions or concerns for the spent fuel pool rack criticality safety analysis, although future limitations on the use of the spent fuel pool storage areas were indicated.

The Boraflex Monitoring Program has been effective in identification of conditions and program deficiencies. Appropriate corrective actions have been implemented. This provides assurance that the program will remain effective for managing loss of material. The history of identification of degradation and initiation of corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for passive components.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.4 provides the UFSAR supplement for the Boraflex 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 3.0-1. The staff also noted that the applicant committed (Commitment No. 4) to ongoing implementation of the existing Boraflex Monitoring Program for managing aging of applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Boraflex 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 through Commitment No. 4 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function 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 Buried Piping and Tanks Inspection

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.5 describes the new Buried Piping and Tanks Inspection Program as consistent with GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks." The LRA states that the AMP addresses buried

and underground piping and tanks constructed of any material exposed to soil to manage the effects of loss of material from the external surfaces of the component. In its annual update letter dated October 25, 2013, the applicant amended its Buried Piping and Tanks Inspection Program to address LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks,'" which was issued in its final version on August 2, 2012. In this amendment, the applicant stated that the program will be consistent with GALL Report AMP XI.M41, as modified by LR-ISG-2011-03.

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.M41, as modified by LR-ISG-2011-03. 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 RAIs, as discussed below.

The "scope of program" program element in GALL Report AMP XI.M41 recommends that underground piping be age managed by AMP XI.M41. However, during its audit, the staff noted that LRA Section B.1.18, External Surfaces Monitoring Program, states an enhancement to its "detection of aging effects" program element to include underground components within the scope of the External Surfaces Monitoring Program. In addition, during the audit, the staff reviewed a partial list of components that appear to be under the scope of the External Surfaces Monitoring Program instead of the Buried Piping and Tanks Inspection Program such as the residual heat removal (RHR) pump suction barrels, high-pressure core spray (HPCS) pump suction barrels, and fuel oil transfer pump discharge stop check valves. By letter dated April 16, 2012, the staff issued RAI B.1.5-1 requesting that the applicant provide a list of all underground (i.e., below grade but contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is restricted) in-scope components, state which AMP will be used to manage the aging of these underground in-scope components, and if a program other than Buried Piping and Tanks Inspection Program will be used to age manage any of the underground components, state which recommendations contained in AMP XI.M41 will not be met and provide justification for not meeting those recommendations.

In its response dated May 14, 2012, the applicant stated that:

(a) the RHR pump suction barrels, HPCS pump suction barrels, and fuel oil transfer pump discharge stop check valves are the only underground components within the scope of license renewal

(b) the components are managed by the External Surfaces Monitoring Program, "because they are neither piping nor tanks but are valves and pump columns that don't fall under the scope of the XI.M41, 'Underground Piping and Tanks Program'"

(c) the components are constructed of carbon steel and are coated

(d) the components will be inspected every 5 years starting 10 years prior to entry into the period of extended operation, and

(e) the inspection frequencies and preventive actions meet or exceed the recommendations of AMP XI.M41

The staff finds the applicant's response acceptable because the inspection frequency of every 5 years starting 10 years prior to the period of extended operation (confirmed by the staff in LRA

Section B.1.18, enhancement to the “detection of aging effects” program element) will result in more inspections than recommended by AMP XI.M41. Further, the external surfaces of the components are coated, and therefore, meet the preventive action recommendations of AMP XI.M41. Therefore, the applicant is meeting all applicable underground piping recommendations from AMP XI.M41. The staff disagrees with the applicant’s statement in relation to the scope of AMP XI.M41 (see (b) above) because Section IX.B of the GALL Report defines piping, piping components, piping elements, and tanks as, “examples include piping, fittings, tubing, flow elements/indicators, demineralizers, nozzles, orifices, flex hoses, pump casings and bowls, safe ends, sight glasses, spray heads, strainers, thermowells, and valve bodies and bonnets,” and therefore, pump suction barrels and valves are in the scope of GALL Report AMP XI.M41. However, in its response (see (a) above), the applicant stated that it will manage aging of the external surfaces of all in-scope underground components with either its Buried Piping and Tanks Inspection or External Surfaces Monitoring Programs, both of which have appropriate preventive actions (i.e., coating), inspection method, and inspection frequency. The staff’s concern described in RAI B.1.5-1 is resolved.

The “preventive actions” program element in GALL Report AMP XI.M41 recommends that coatings are in accordance with Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002. However, during its audit, the staff found that a condition report stated that the Division II diesel fuel oil storage tank coatings had anomalies. It is not clear to the staff if these anomalies result in the coatings not meeting the recommendations of AMP XI.M41, and therefore the discrepancy should be justified by the applicant. By letter dated April 16, 2012, the staff issued RAI B.1.5-2 requesting that the applicant state whether the coating anomalies described in the condition report were corrected, and if not, state whether these anomalies are such that the coatings will meet specifications in Section 3.4 of NACE RP0285-2002 or not. If the coatings do not meet Section 3.4 of NACE RP0285-2002, state the basis for why there is a reasonable assurance that the tanks will meet their CLB function(s) throughout the period of extended operation.

In its response dated May 14, 2012, the applicant stated that the anomalies are on the internal surfaces of the tank, none of the anomalies are located on the tank bottom where water and sludge accumulate. Further, the applicant’s engineering evaluation determined that the anomalies were acceptable as-is based on their location and that no loss of wall thickness was observed, and a follow-on inspection is scheduled for 2016, which is prior to the period of extended operation.

The staff finds the applicant’s response acceptable because the anomalies are located on the inside of the tank and therefore not within the scope of AMP XI.M41. The staff noted that even though the coating anomalies were reported on the inside surface of the tank and not in the scope of AMP XI.M41, the staff finds the applicant’s disposition acceptable because no wall loss was noted at the locations, and the applicant’s engineering evaluation has indicated that the locations are acceptable. Further, the locations are not susceptible to significant degradation due to being above the tank bottom, and a follow-on inspection will occur prior to the period of extended operation. The staff’s concern described in RAI B.1.5-2 is resolved.

The “preventive actions” program element in GALL Report AMP XI.M41 recommends that protective coatings be provided (stainless steel piping is not required to be coated if soil conditions will not degrade the external surfaces of the piping) and backfill be consistent with NACE SP0169-2007 and RP0285-2002. However, during its audit, the staff could not verify that (a) steel in-scope systems are coated, (b) initial backfill specifications are consistent with recommendations in AMP XI.M41, and (c) in-scope stainless steel components were coated, or if they have not been coated, if sufficient soil samples were obtained that demonstrated that the soil environment would not result in aging of the external surfaces of the piping. By letter dated April 16, 2012, the staff issued RAI B.1.5-4 requesting that the applicant (a) state whether buried in-scope steel piping components and tanks are coated and what coating material was used, (b) describe the specifications for initial backfill in the vicinity of buried in-scope piping components and tanks, and (c) state if buried in-scope stainless steel components are coated and with what coating material, or if they have not been coated, if sufficient soil samples were obtained that demonstrated that the soil environment would not result in aging of the external surfaces of the piping. The RAI also requested that—if the stainless steel components are not coated and soil sampling results are not available or acceptable—the applicant state the basis for why there is a reasonable assurance that the piping will meet its CLB function(s) throughout the period of extended operation.

In its response dated May 14, 2012, the applicant stated that (a) buried in-scope steel piping is coated with coal tar enamel and tanks are coated with coal tar epoxy, (b) backfill meets a grain size range of 0.1 to 5 mm, and no organic perishable or deleterious materials (e.g., roots, snow, ice, debris) are permitted, and (c) there are two stainless steel pipe lines that are routed in close proximity to each other, neither of which is coated, there is no soil testing data to demonstrate that the soil does not contain deleterious compounds that could degrade the stainless steel material; and one visual inspection will be conducted in the 10-year period prior to the period of extended operation to determine if additional inspections are required.

The staff finds the applicant's response to parts (a) and (b) above, acceptable because the coatings and backfill meet the recommendations of AMP XI.M41. The staff's concerns described in RAI B.1.5-4 parts (a) and (b) are resolved. However, the staff did not find the response to part (c) acceptable because the stainless steel piping is not coated, no soil sample results are available, and despite not meeting the preventive action recommendation of AMP XI.M41, no further inspections beyond those recommended in the AMP are proposed. Based on this, the staff lacked sufficient information to complete its evaluation of the buried uncoated stainless steel piping.

By letter dated July 17, 2012, the staff issued RAI B.1.5-4a requesting that the applicant revise the Buried Piping and Tanks Inspection Program to include a method to determine the condition of the buried uncoated in-scope stainless steel piping prior to the period of extended operation, or include soil testing with possible augmented inspections prior to and during the period of extended operation.

In its response dated August 13, 2012, the applicant stated that it will perform soil testing prior to the period of extended operation consisting of two samples near the stainless steel piping. The samples will be analyzed for soil resistivity, bacteria, pH, moisture, chlorides and redox potential. If the soil is determined to be corrosive, the applicant will increase inspections from one to two, prior to and during the period of extended operation. The applicant revised LRA Section A.1.5, UFSAR Supplement, to reflect the response.

The staff finds the applicant's response acceptable because:

- Multiple soil samples will be taken to determine soil corrosivity.
- The soil sample parameters are consistent with LR-ISG-2011-03, with the exception of sulfate testing.

- The lack of sulfate testing is acceptable because “Corrosion Resistance of Stainless Steels in Soils and in Concrete,” paper presented at the Plenary Days of the Committee on the Study of Pipe Corrosion and Protection, Ceocor, Biarritz, October 2001 by Pierre-Jean Cunat states, “[c]ompared to the aggressivity of chloride ion levels, sulphates are generally considered to be less aggressive. The presence of sulphates may pose a risk for some stainless steels in the sense that sulphates can be converted to highly corrosive sulphides by anaerobic sulphate reducing bacteria.” Given that the applicant will test for bacteria, the likelihood of sulfates causing degradation of the stainless steel piping is low.
- If the soil is determined to be corrosive, the number of inspections will be doubled from one to two. This is consistent with LR-ISG-2011-03, Table 4a, “Inspections of Buried Pipe,” where the inspection quantities are doubled for steel piping when nonconforming coatings, adverse plant-specific OE, or unacceptable soil testing results are obtained.
- The applicant updated its UFSAR supplement, thereby ensuring that the augmented inspection requirements, if the soil is corrosive, become part of the current licensing basis during the period of extended operation.

The staff’s concern described in RAI B.1.5-4a is resolved.

The “detection of aging effects” program element in GALL Report AMP XI.M41 recommends that buried and underground piping inspection locations are selected based on risk. However, during its audit, the staff noted that the applicant’s fleet procedure states that, “[i]n general, inspections should be performed at the segments that have the highest risk ranking as determined above.” It is not clear to the staff that the “in general” and “should be” modifiers in the procedure are consistent with AMP XI.M41 because they could lead to lower risk inspection locations being selected based on criteria not presented to the staff. By letter dated April 16, 2012, the staff issued RAI B.1.5-5 requesting that the applicant state how the “in general” and “should be” modifiers quoted above are consistent with AMP XI.M41, which provides no such alternatives.

In its response dated May 14, 2012, the applicant stated that the Buried Piping and Tanks Inspection Program is a new program and when procedures are developed, they will be consistent with AMP XI.M41. The applicant also stated that, “[t]he intent of the phrases ‘[i]n general’ and ‘should be’ in EN-DC-343 was to allow some latitude for not inspecting a location with the highest risk ranking if factors such as inaccessibility would preclude an effective inspection. In those cases, a segment from the next highest risk category would be inspected.”

The staff reviewed the applicant’s response and noted that GALL Report AMP XI.M41 does not provide specific inspection locations when the highest risk-ranked piping is not accessible. The staff agrees that there may be cases in which the highest risk-ranked piping is not sufficiently accessible to ensure an effective inspection. The staff finds the applicant’s proposal acceptable because if the highest risk-ranked piping is not accessible, it will inspect the next highest risk-ranked piping and therefore, the selection of piping inspection locations will be biased to the highest available risk-ranked locations. The staff’s concern described in RAI B.1.5-5 is resolved.

The “acceptance criteria” program element in GALL Report AMP XI.M41 recommends that the criteria for pipe-to-soil potential be consistent with NACE SP0169-2007 for which paragraph 6.2.2.3.3 states that the use of excessive polarization potential can result in coating disbondment. During its audit, the staff reviewed a recent survey report and noted that the test demonstrated that 93 percent of the in-scope buried piping was receiving adequate cathodic protection; however, the only acceptance criterion was a 100 mV of cathodic polarization of the piping and soil potential. The staff was not able to verify whether the cathodic protection criterion the applicant used would not lead to pipe-to-soil potentials more negative than -1,200 mV with respect to a saturated copper/copper sulfate reference electrode. In addition, given that the in-scope piping is within a mixed metal environment, the staff lacked sufficient information to conclude that the singular 100 mV of cathodic polarization criterion is sufficient to establish that adequate cathodic protection has been applied. By letter dated April 16, 2012, the staff issued RAI B.1.5-6 requesting that the applicant (a) state the maximum negative potential that will be accepted for steel and stainless steel buried in-scope components, (b) if as-left pipe-to-soil potentials are more negative than -1200 mV with respect to a saturated copper/copper sulfate reference electrode, state why there is a reasonable assurance that the piping will meet its CLB function(s) throughout the period of extended operation, and (c) state the basis for the conclusion that the 100 mV of cathodic polarization criterion is sufficient to ensure that the most active buried in-scope piping material has achieved a sufficient cathodic polarization for corrosion protection.

In its response dated May 14, 2012, the applicant stated that when the program is implemented, a limit of -1,200 mV will be established. The applicant also stated that:

> Adequacy of polarization can be indicated by both the 100 mV polarization criterion as well as the 850 mV instant “off” polarized criterion. Ohm’s law dictates that polarization at the cathode of a CP system circuit must occur, although possibly at different levels, simultaneously everywhere in the circuit. This means that the potentials measured at the ground surface for both the 100 mV and the 850 mV criteria are representative of what is taking place at all locations on the bare surfaces of the buried piping and structures. Thus, any singular 100 mV polarization indication ensures that the most active buried piping material has achieved protection, as would be the case for a singular 850 mV polarized half-cell reading.

The staff finds the applicant’s response to parts (a) and (b) above acceptable because it will establish a -1200 mV limit for cathodic protection. The staff’s concerns described in RAI B.1.5-6 parts (a) and (b) are resolved. However, the staff did not find the response to part (c) acceptable because it was insufficient to demonstrate that the most active (e.g., most anodic) buried in-scope piping material has achieved a sufficient polarization level to manage aging of the buried components, in that it did not address the mixed metal environment of the buried piping.

By letter dated July 17, 2012, the staff issued RAI B.1.5-6a requesting that the applicant state why a 100 mV polarization is adequate to protect steel and stainless steel buried components when there is a nearby bare wire copper grid and how the testing methodology ensures that the steel and stainless steel buried piping has achieved a sufficient level of polarization.

In its response dated August 13, 2012, the applicant cited three bases for the acceptability of 100 mV polarization criteria. These bases are noted below, as are the staff’s positions on the bases. Staff did not agree with the first two bases and lacked sufficient information to complete the evaluation of the third.

- In the first basis, the applicant cited NACE Corrosion Engineer’s Reference Handbook and stated that since both steel and copper can be cathodically protected by applying a minimum of 100 mV polarization, then, “with the CP system raising the piping and grounding grid to an equipotential voltage of 100 mV, galvanic action is nullified.” The staff reviewed the applicant’s source, “NACE Corrosion Engineer’s Reference Book,” Third Edition, Robert Baboian, editor, page 161. A 100 mV of cathodic protection polarization between the structure and a reference electrode does not raise the two components (i.e., steel piping and copper ground grid) to the same potential, but rather would raise each component’s potential relative to the reference electrode to which it is being measured. The staff noted that this could still result in the mixed metal free corrosion potential remaining in the oxidizing range for the steel piping.

- In the second basis, the applicant again cited the NACE Corrosion Engineer’s Reference Handbook and stated that the handbook specifies that a target current density is 0.1 mA/ft^2 to 0.2 mA/ft^2. The applicant also stated that the protected area at the station is 22.175 acres and the applied current from the rectifiers is 214.65 amps resulting in an average current density of 0.2 mA/ft^2. The staff reviewed page 162 of the reference and concluded that the cited target current density represents an approximate current requirement for steel piping. The staff believes that this target current density should not be considered as an acceptance criteria for cathodic protection because it does not address localized conditions and it could be met by buried components with degraded coatings, which result in greater current demand.
- In the third basis, the applicant stated that if buried steel components and the bare wire copper grounding grids were in close proximity or mixed metal couples were occurring, a plot of the native potential data would show a mean of 350 mV. The mean at the site is 427 mV. The staff could not locate the source of the 350 mV criterion, and therefore, could not accept this basis.

The applicant also stated that area potential earth current (APEC) surveys would ensure that an adequate level of polarization would be achieved for buried steel and stainless steel components. The APEC survey defines significantly active corrosion cells, determines the plant piping coating condition, and evaluates the performance of all influencing CP systems from a detailed graphical representation. The staff noted that an APEC survey is usually conducted as a combination of close interval survey and direct current voltage gradient surveys. While the staff agrees that APEC surveys can provide information related to localized potentials and current flow, did not agree that use of the 100 mV minimum polarization coupled with APEC surveys is sufficient to demonstrate adequate cathodic protection, without the use of buried corrosion test coupons, because there is the potential for the survey technique to be affected by other buried components or structures.

By letter dated September 14, 2012, the staff issued RAI B.1.5-6b requesting that the applicant (a) provide the source documents which establish the basis for the mean 350 mV criterion, (b) submit the complete last APEC survey report and, if APEC surveys will be used to confirm the effectiveness of the 100 mV polarization criterion, revise the Buried Piping and Tanks Inspection Program and UFSAR supplement to reflect its use, (c) state what methods will be used to confirm the results of the APEC surveys and revise the Buried Piping and Tanks Inspection Program and UFSAR supplement to reflect the use of this method, and (d) state what actions will be taken if the alternative method utilized to confirm the APEC surveys indicates that corrosion of in-scope buried components is occurring more rapidly than expected.

In its response dated October 15, 2012, the applicant stated that its program will be consistent with NACE SP0169 and the 100 mV criterion will not be used in lieu of the -850 mV criterion. The staff finds the applicant’s response acceptable because the use of the -850mV criterion is consistent with Table 6a, "Cathodic Protection Acceptance Criteria," of LR-ISG-2011-03, the current staff position on cathodic protection acceptance criteria. Given this change in acceptance criteria, the applicant does not need to respond to the specific questions in RAI B.1.5-6b. The staff's concerns described in RAIs B.1.5-6a and B.1.5-6b are resolved.

Based on its audit, review of the applicant's responses to RAIs B.1.5-1, B.1.5-2, B.1.5-4, B.1.5-4a, B.1.5-5, B.1.5-6, B.1.5-6a, and B.1.5-6b, and review of the amended program submitted by letter dated October 25, 2013, 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, as modified by LR-ISG-2011-03.

Operating Experience. LRA Section B.1.5 summarizes operating experience related to the Buried Piping and Tanks Inspection Program. The applicant stated that an area potential earth current survey was performed before installation of a new cathodic protection system in December 2009. The survey did not find any degraded conditions; however, two areas were noted to have a higher potential for coating degradation.

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 AMP 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 RAI B.1.5-3, as discussed below in UFSAR supplement.

Based on its audit and review of the application, and review of the applicant's response to RAI B.1.5-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.5 provides the UFSAR supplement for the Buried Piping and Tanks Inspection 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 licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate information related to operation of the cathodic protections system into its UFSAR supplement.

The "preventive actions" and "monitoring and trending" program elements in GALL Report AMP XI.M41 recommend that a cathodic protection system be installed, monitored, annually tested, and potential differences and current measurements be trended to identify changes in the effectiveness of the system. However, during its audit, the staff identified six condition reports spanning 2006 through 2011 citing significant gaps in cathodic protection system performance. The plant-specific operating experience is not consistent with the AMP XI.M41 recommendations because it demonstrates a long period of inadequate performance of the cathodic protection system; therefore, cathodic protection may not be consistent with AMP XI.M41. By letter dated April 16, 2012, the staff issued RAI B.1.5-3 requesting that the applicant modify its UFSAR supplement to include the availability of the cathodic protection system, monitoring frequency for effectiveness, and trending parameters, or justify its exclusion.

In its response dated May 14, 2012, the applicant revised LRA Section A.1.5 to include the following statement: “cathodic protection is used for additional protection of buried piping and tanks. The cathodic protection system is monitored and trended annually in accordance with NACE standards SP-0169 and RP-0285.”

The staff finds the applicant’s response acceptable because the applicant’s UFSAR supplement now includes utilization of a cathodic protection system and its monitoring and trending during annual surveys conducted in accordance with the NACE standards recommended in AMP XI.M41. The staff’s concern described in RAI B.1.5-3 is resolved.

As amended by letter dated October 25, 2013, the applicant revised the UFSAR supplement to include a statement that preventive and mitigative actions include selection of materials, coatings, backfill quality, and cathodic protection. The staff finds this change acceptable because these preventive and mitigative actions are consistent with GALL Report AMP XI.M41 as modified by LR-ISG-2011-03.

The staff also noted that the applicant committed (Commitment No. 5) to implement the new Buried Piping and Tanks Inspection Program prior to 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 October 25, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant’s Buried Piping and Tanks Inspection 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.M41, as modified by LR-ISG-2011-03. 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 CRD Return Line Nozzle

Summary of Technical Information in the Application. LRA Section B.1.6 describes the existing BWR Control Rod Drive (CRD) Return Line Nozzle Program as consistent, with enhancement, with GALL Report AMP XI.M6, “BWR Control Rod Drive Return Line Nozzle.”

The LRA states that the program manages cracking of the CRD return line nozzle using preventive, mitigative, and inservice inspection (ISI) activities, in accordance with the applicant’s commitments to GL 80-095, to implement the recommendations in NUREG-0619, “BWR Feedwater Nozzle and Control Rod Driven Return Line Nozzle Cracking,” issued November 1980.

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.M6. For the applicant’s “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

GALL Report AMP XI.M6, “BWR Control Rod Drive Return Line Nozzle,” states that this program is a condition monitoring program based on the staff’s recommended position in NUREG-0619 for thermal fatigue and the program is also intended to address SCC discussed in NRC Information Notice (IN) 2004-08, “Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds.” IN 2004-08 addresses cracking due to SCC of capped CRD return lines. In addition, the GALL Report AMP “parameters monitored or inspected” program element also states that the AMP manages the effects of cracking on the intended function of the RV, the CRD return line nozzle, and for capped nozzles, the capped nozzle caps, and nozzle-to-cap welds. The GALL Report AMP further states that using the volumetric examinations (UT) that are performed in accordance with this AMP, the AMP monitors and evaluates signals that may indicate the presence of a planar flaw (crack). During its audit, the staff noted that the applicant’s CRD return line is capped and its current ISI plan includes the CRD return line nozzle in its scope and sample population for the ISI.

During the audit, the staff noted that the applicant’s current ISI plan does not have a specific inspection schedule for the CRD return line, which indicates that the CRD return line has not been selected for inspection during the current inspection interval. Therefore, the staff required additional information related to the lack of a specific inspection schedule for this component because it does not ensure adequate detection and management of cracking due to SCC of the CRD return line.

By letter dated April 3, 2012, the staff issued RAI B.1.6-1 requesting that the applicant provide additional information on the size, material, number of associated welds, and configuration of the applicant’s CRD line. The staff also requested clarification as to how the applicant’s boiling water reactor (BWR) Control Rod Drive Return Line Nozzle Program is consistent with the GALL Report AMP, given that the current ISI plan does not contain a specific inspection schedule for the CRD return line. In addition, the staff requested that the applicant clarify if the CRD return line nozzle-to-cap welds will be examined before or during the period of extended operation. Alternatively, in consideration of the industry experience of SCC described in NRC IN 2004-08, the staff requested that the applicant provide justification as to why it is not necessary to examine the CRD return line nozzle-to-cap welds to detect and manage cracking due to SCC.

In its response dated May 1, 2012, the applicant stated that the 3.5-inch outside diameter CRD return nozzle-to-cap weld to the carbon steel safe end is Inconel filler material with Alloy 182 butter weld, and the cap material is Inconel 600. The applicant also stated that no recordable flaw indications were observed during ultrasonic examination performed in 2004 on its CRD return line nozzle-to-cap dissimilar metal (DM) weld. The applicant also stated that an enhancement would be added to the program to inspect the CRD return line nozzle weld once before the period of extended operation and every 10 years thereafter so that the integrity of the CRD return line nozzle-to-cap weld can be ensured for the period of extended operation.

The staff finds the applicant’s response acceptable because the applicant performed ultrasonic examination in 2004, which confirmed that there was no recordable flaw observed on the nozzle-to-cap dissimilar weld. Since the materials of construction for its nozzle-to-cap dissimilar weld may be susceptible to SCC, the applicant has appropriately enhanced the program to ensure that inspections will continue to be performed to verify that the preventive actions will continue to be effective during the period of extended operation. In addition, continued inspection will provide adequate assurance that SCC will be detected before loss of intended function during the period of extended operation. Therefore, the staff’s concern discussed in

RAI B.1.6-1 is resolved. The evaluation of the applicant's enhancement is discussed in the section for the enhancement.

Enhancement. By letter dated May 1, 2012, the applicant amended the LRA and identified an enhancement that inspections will be performed on the CRD return line nozzle-to-cap DM weld, once before the period of extended operation, and every 10 years thereafter. The applicant also revised LRA Section A.1.6 (UFSAR supplement) and LRA Section B.1.6 to reflect the enhancement, and identified the enhancement as Commitment No. 32.

The staff finds the applicant's enhancement acceptable because it is consistent with GALL Report AMP XI.M6, and will address potential cracking of DM welds for the capped CRD return lines due to SCC, which is discussed in NRC IN 2004-08.

Summary. Based on its audit, and review of the applicant's response to RAI B.1.6-1, the staff finds that elements one through six of the applicant's program, with the enhancement, are consistent with the corresponding program elements of GALL Report AMP XI.M6, and therefore, acceptable. In addition, the staff reviewed the enhancement associated with the "detection of aging effects" program element and finds when implemented, it will enable the AMP to adequately manage the applicable aging effects.

Operating Experience. LRA Section B.1.6 summarizes operating experience related to the BWR CRD Return Line Nozzle Program. The applicant stated that ultrasonic examinations performed in 2004 on the return line nozzle-to-cap dissimilar weld metal did not reveal any crack indication. The applicant also stated that the absence of aging effects indicates that the preventive actions of the program have been effective.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.6 provides the UFSAR supplement for the BWR Control Rod Drive Return Line Nozzle 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 applicant committed (Commitment No. 32) to include inspection of the CRD return line nozzle end cap to carbon steel safe end DM weld once prior to the period of extended operation and every 10 years thereafter. The staff finds the information in the UFSAR supplement, as amended by letter dated May 1, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's BWR Control Rod Drive Return Line Nozzle Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 32 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 BWR Feedwater Nozzle

Summary of Technical Information in the Application. Section B.1.7 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 due to 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 applicant stated that its BWR Feedwater Nozzle Program consists of ISI in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB, and the recommendations of General Electric (GE) NE-523-A71-0594-A. The program specifies periodic ultrasonic inspection of critical regions of the FW nozzles.

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.M5.

In particular, the staff confirmed that the AMP addresses the detection and sizing of cracks by ISIs 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, IWA-4000.

Based on its audit of the applicant's BWR Feedwater Nozzle, the staff finds that program elements one through six 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.1.7 summarizes operating experience related to the BWR Feedwater Nozzle Program. Indication was detected in 1995 and analysis of the ultrasonic examination data was performed and found to be acceptable. The applicant also stated that all six FW nozzle blend radii as well as two nozzle-to-safe end welds were inspected in 1998 and 2002, and no indications were recorded.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.7 provides the UFSAR supplement for the BWR Feedwater Nozzle. The staff reviewed this UFSAR supplement description of the program and noted that the program augments the examinations specified in the ASME Code Section XI, with the recommendation of GE NE-523-A71-0594, rather than GE-NE-523-A71-0594, Revision 1, which is the revision recommended in GALL Report AMP XI.M5.

By letter dated April 3, 2012, the staff issued RAI B.1.7-1 requesting that the applicant include the correct revision of the GE report in its UFSAR supplement for this program. In its response dated May 1, 2012, the applicant revised LRA Section A.1.7 to state that the program is based on the guidelines of GE NE-523-A71-0594, Revision 1. The staff finds the applicant's response acceptable because the description of the BWR Feedwater Nozzle Program in the UFSAR supplement includes the correct version of the GE report, which will ensure the licensing basis will be adequately maintained during the period of extended operation. The staff's concern described in RAI B.1.7-1 is resolved. The staff finds that the information in the UFSAR supplement, as amended by letter dated May 1, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's BWR Feedwater Nozzle AMP, 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).

3.0.3.1.7 BWR Penetrations

Summary of Technical Information in the Application. LRA Section B.1.8 describes the existing BWR Penetrations Program as consistent, with enhancement, with GALL Report AMP XI.M8, "BWR Penetrations." The LRA states that the BWR Penetrations Program is an existing program that manages cracking of BWR vessel penetrations using inspection and flaw evaluation activities. The LRA states that applicable industry standards and staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) documents are used to manage cracking of the RV penetrations.

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.M8, "BWR Penetrations." For the "parameters monitored or inspected" and "scope of program" 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 GALL Report AMP XI.M8, “BWR Penetrations,” states that the program manages the effects of cracking due to SCC and intergranular stress-corrosion cracking (IGSCC) on the intended function of the BWR instrumentation nozzles, CRD housing, and in-core monitoring housing (ICMH) penetrations, and BWR standby liquid control (SLC) nozzles/Core ΔP nozzles. The GALL Report also states that the program accomplishes this by inspection for cracks in accordance with the guidelines of approved BWRVIP-49-A, BWRVIP-47-A, or BWRVIP-27-A and the requirements of the ASME Code, Section XI, Table IWB 2500-1.

In addition, Section 3.2.5, “Other Inspections,” in BWRVIP-47-A indicates that the BWRVIP has determined that removing or dismantling of internal components for the purpose of performing inspections is not warranted to assure safe operation; however, on occasion, utilities may have access to the lower plenum due to maintenance activities not part of normal refueling outage activities. BWRVIP-47-A further states that in such cases, utilities will perform a visual inspection to the extent practical for implementation of the examinations.

During the audit, the staff noted that the site documentation for the BWR Penetrations Program indicated that the baseline inspections for the CRD housing do not require access to the lower plenum area and that currently no additional inspections are recommended beyond the baseline inspections. In addition, the staff noted that the site documentation indicated that, if access is gained to the lower plenum (areas below the core plate), the accessible areas of the in-core flux monitor housing, guide tubes and guide tube stabilizer should be inspected using a visual VT-3 inspection method. However, it was not clear to the staff whether the additional VT-3 inspections would be applied to the monitoring of in-core flux monitoring housing penetrations.

By letter dated April 3, 2012, the staff issued RAI B.1.8-1 requesting that the applicant provide information on whether the lower plenum housings and penetrations would be accessible during maintenance activities that are scheduled outside of normal refueling outage maintenance activities. The staff also requested that the applicant justify why the BWR Penetrations Program does not include the additional inspections of the CRD housings and housing penetrations (including stub tubes) described in Section 3.2.5 of BWRVIP-47-A. In addition, the staff requested that the applicant clarify if the additional inspections are applied to the in-core flux monitoring housing penetrations.

In its response dated May 1, 2012, the applicant stated that the lower plenum housings and penetrations are not accessible during maintenance activities associated with a normal refueling outage, and there currently are no scheduled maintenance activities that will provide access to the lower plenum. The applicant also clarified that if the lower plenum housing and penetration area were to become accessible, Section 3.2.5 guidelines of BWRVIP-47-A for the inspections would be followed.

The applicant further clarified that, as stated in license renewal project documents, the BWR Penetrations Program manages cracking on the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and BWR SLC nozzles/core ΔP nozzles using applicable ASME Section XI inspection and flaw evaluation, as required in accordance with 10 CFR 50.55a and applicable requirements in ASME Section XI, Table IWB-2500-1. These methods are discussed in the staff-approved BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A reports. In addition, the applicant stated that it has not taken any exception to the guidance in Section 3.2.5 and as such will perform all applicable actions.

The applicant also stated that the LRA indicates consistency of the BWR Penetrations Program with the methodology in the NRC-approved BWRVIP-47-A report; therefore, the AMP does not require any changes or modifications of its program elements. The applicant further stated that, as such, the program will perform the applicable inspections recommended in the BWRVIP-47-A report and are required to be implemented in accordance with ASME Code Section XI. The applicant stated that these inspections include inspections of the CRD housings and penetrations.

The applicant also indicated that the site procedures, which implement the guidelines of BWRVIP-47-A, will be modified to provide additional clarification on the use of BWRVIP-47-A guidance for the inspections of the RV penetrations. In addition, the applicant's response identifies that an enhancement to the "parameters monitored or inspected" program element is needed based on its response to RAI B.1.8-1. The applicant stated that, under this enhancement, the applicant committed to enhancing the site procedures to clearly indicate that the BWRVIP-47-A guidelines will be applied without exceptions. The staff's evaluation of this enhancement is further described in the evaluation section for the enhancement.

Based on this review, the staff finds the applicant's response acceptable because the staff has confirmed that the applicant's BWR Penetrations Program is consistent with the BWRVIP documents referenced in GALL Report AMP XI.M8, including the guidance in Section 3.2.5 of BWRVIP-47-A. The staff's concern described in RAI B.1.8-1 is resolved.

The staff noted that LRA Table 3.1.2-1 addresses the applicant's aging management of the RV, including RV nozzles and penetrations. The staff also noted that LRA Table 3.1.2-1 includes Table 2 AMR items that credit the BWR Vessel Internals Program and Water Chemistry Control – BWR Program to manage cracking due to SCC, IGSCC, and cyclic loading in the CRD housing penetrations and in-core housing penetrations. The applicant's AMR items are linked to LRA items 3.1.1-102 and 3.1.1-98, which are given in LRA Table 3.1.1.

The staff noted that the GALL-recommended scope of the BWR Penetrations Program and GALL Report Item IV.A1.RP-369 indicate that the BWR Penetrations Program and Water Chemistry Program should be used to manage cracking of these RV penetrations during the period of extended operation. Therefore, the staff noted that the applicant's AMR results for cracking of the CRD housing penetrations and in-core housing penetrations were not consistent with the scope of GALL Report AMP XI.M8, "BWR Penetrations Program," or with the AMR recommendations in GALL Report AMR Item IV.A1.RP-369.

By letter dated July 23, 2012, the staff issued RAI B.1.8-4 requesting that the applicant justify why cracking due to SCC, IGSCC and cyclic loading of the CRD housing penetrations and in-core housing penetrations is managed by the BWR Vessel Internals Program and Water Chemistry Control – BWR Program.

In its response dated August 15, 2012, the applicant stated inspection guidance for the CRD housings and in-core housings is provided in BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," and for the purposes of comparisons to the GALL Report, the BWR Penetrations Program described in GALL Report AMP XI.M8, which references BWRVIP-47-A, better represents the AMP requirements. In its response, the applicant also provided revisions to LRA Table 3.1.2-1 and LRA Table 3.1.1, item 3.1.1-98, to identify that the BWR Penetrations and Water Chemistry Control - BWR Programs manage cracking of the CRD housing penetrations and in-core housing penetrations, consistent with the GALL Report.

The staff finds the applicant's response acceptable because its revisions to the LRA are consistent with the GALL Report, which recommends the BWR Penetration Program in conjunction with the Water Chemistry Program to manage cracking of the CRD and in-core housing penetrations. The staff also finds that the BWR Penetrations Program includes the examinations specified in the BWRVIP-47-A and ASME Code Section XI, which are adequate to detect and manage cracking of these RV penetrations. The staff's concern described in RAI B.1.8-4 is resolved.

The staff also reviewed the portions of the "parameters monitored or inspected" 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. By letter dated May 1, 2012, the applicant provided its response to RAI B.1.8-1 and amended LRA Sections A.1.8 (UFSAR supplement) and B.1.8 to include an enhancement of the "parameters monitored or inspected" program element for the BWR Penetration Program. The applicant also identified this enhancement as Commitment No. 33. In this enhancement, the applicant stated that site procedures, which implement the guidelines of BWRVIP-47-A, will be clarified to indicate that the guidelines of BWRVIP-47-A will be applied as the basis for the program without exception. The applicant also stated that the enhancement will be implemented prior to the period of extended operation.

In its review, the staff finds that the applicant's program is consistent with GALL Report AMP XI.M8. In addition, the applicant's enhancement will clearly indicate that the site procedures are consistent with the guidelines of Section 3.2.5, "Other Inspections," in BWRVIP-47-A as referenced in the GALL Report. The staff also confirmed that the applicant has included this enhancement in UFSAR supplement Section A.1.8 of the LRA, "BWR Penetrations," as amended in the applicant's letter, dated May 1, 2012.

The staff reviewed the applicant's BWR Penetrations Program, as subject to the applicant's enhancement of the procedure that will be implemented by this program, against the corresponding program element in GALL Report AMP XI.M8, "BWR Penetrations." Based on this review, the staff finds that the enhancement is acceptable because the staff has confirmed the program is consistent with the GALL Report and the implementation of the enhancement will clearly indicate that the site procedures for the program are consistent with the recommended inspection and evaluation guidelines in BWRVIP-47-A.

Summary. Based on its audit, and review of the applicant's responses to RAIs, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M8. In addition, the staff reviewed the enhancement associated with the "parameters monitored or inspected" program element and finds that when implemented, it will make the AMP adequate to manage the applicable aging effects.

Review of License Renewal Applicant Action Items. The staff's safety evaluation (SE), dated September 1, 1999, for BWRVIP-49, "BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines," addresses three license renewal applicant action items (AAIs). In addition, the staff's SE, dated December 7, 2000, identifies four applicant renewal AAIs for BWRVIP-47, "BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines (BWRVIP-47)." Furthermore, the staff's SE, dated December 20, 1999, identifies four applicant renewal action items for BWRVIP-27, "BWR

Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines (BWRVIP-27).”

Of these AAIs, three of them are common to the BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49 reports. The fourth action item in this evaluation is specific to the methodology in the BWRVIP-47-A report and the fifth action item in this evaluation is specific to the methodology in the BWRVIP-27-A report.

The applicant provided its responses to these AAIs in LRA Appendix C. The staff’s evaluation of the applicant’s responses to these AAIs is described in the paragraphs that follow.

The staff noted that AAI No. 1 states that the license renewal applicant is to verify that its plant is bounded by the BWRVIP reports and the applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. In its response to AAI No. 1, the applicant stated that the BWRVIP reports have been reviewed and GGNS has been confirmed to be bounded by the BWRVIP reports. The applicant also committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. The applicant further stated that the implementation of these commitments is administratively controlled in accordance with the requirements of 10 CFR Part 50, Appendix B.

In its review, the staff finds that the applicant has adequately addressed AAI No. 1 because: (a) the applicant confirmed that its program is bounded by the BWRVIP reports, (b) the staff also found that the BWR Penetrations Program is an existing program that is both being implemented during the current operating period and will be implemented during the period of extended operation, and (c) the staff has confirmed that the BWR Penetration Program with the enhancement is consistent with the program elements recommended in GALL Report AMP XI.M8.

The staff noted that AAI No. 2 states that the applicant for license renewal, referencing the applicable BWRVIP reports, shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarized in the UFSAR supplement. In its response to AAI No. 2, the applicant stated that the UFSAR supplement for the BWR Penetrations Program is included in LRA Appendix A and includes a summary of the programs and activities specified as necessary for the BWR Penetrations Program. The staff confirmed that the applicant has included its UFSAR supplement for the BWR Penetrations Program in LRA Appendix A, Section A.1.8. The staff also evaluated the adequacy of the applicant’s UFSAR supplement for the BWR Penetrations Program as described in the evaluation section for the UFSAR supplement. The evaluation includes the staff’s review and approval of RAIs B.1.8-2 and B.1.8-2a regarding LRA Section A.1.8 (UFSAR supplement).

The staff noted that AAI No. 3 states that if the TS changes or additions result from the implementation of the BWRVIP reports, the applicant must ensure that those changes are included in its application for license renewal. In its response to AAI No. 3, the applicant indicated that it did not identify any TS that would need to be changed as a result of its implementation of the guidelines in BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49 reports. The staff reviewed the current set of TS for the facility and confirmed that the TS did not include any TS requirements based on the applicant’s implementation of the inspection and flaw evaluation protocols recommended in BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49 reports.

The staff noted that the applicant implements these inspection and flaw evaluation protocols through the NEI 03-08, “Guideline for the Management of Materials Issues,” augmented inspection and evaluation process for addressing potential material degradation issues that may occur at the facility. Thus, the staff confirmed that the LRA would not need to generate any additional TS changes relative to the implementation of the recommended protocols in these BWRVIP reports. Therefore, the staff finds that the applicant has adequately addressed AAI No. 3 because the staff has confirmed that the LRA does not need to identify any changes of the existing set of TS in the CLB and does not need to generate any new TS for the facility based on the applicant’s BWRVIP-based augmented inspection program for the RV penetrations at the facility.

The staff noted that AAI No. 4 specific to BWRVIP-47 states that due to fatigue of the subject safety-related components, the applicant referencing the BWRVIP-47 report for license renewal should identify and evaluate the projected cumulative usage factor as a potential time-limited aging analysis (TLAA) issue. In its response to AAI No. 4 specific to BWRVIP-47, the LRA indicates that the applicant evaluated its CLB to identify potential TLAAs for the components in the lower plenum area of the RV. The applicant also identified that the only cumulative usage factor (CUF)-based TLAAs applicable to RV lower plenum area penetration nozzles are those identified in LRA Section 4.3.1.1 for fatigue TLAAs.

The staff confirmed that the applicant provided the fatigue TLAAs for the CRD and in-core housing penetrations that need to be evaluated in accordance with the recommendation in BWRVIP-47-A. Based on this review, the staff finds that the applicant adequately addressed AAI No. 4 on the BWRVIP-47-A report because the staff confirmed that: (a) the applicant included the relevant fatigue TLAAs in the LRA that are applicable to penetration nozzles that are joined to the RV lower plenum area, and (b) LRA Section 4.3.1.1 and Table 4.3-2 describe the applicant’s CUF-based TLAAs for the CRD and in-core housing penetrations, which are included within the scope of the applicant’s BWR Penetrations Program.

The staff noted that AAI No. 4 specific to BWRVIP-27 states that due to the susceptibility of the subject components to fatigue, the applicant referencing the BWRVIP-27 report for license renewal should identify and evaluate the projected fatigue CUFs as a potential TLAA issue. In its response to AAI No. 4 specific to BWRVIP-27, the applicant stated that the fatigue analysis of the SLC/core ΔP line for 60 years of operation is a potential TLAA. The applicant also stated that at GGNS, the CS assembly provides the flow path for injection of boron for the SLC system. The applicant further stated that the SLC/core ΔP lines inside the RV have no license renewal-intended function and are not subject to an AMR. In addition, the applicant stated that there are not any TLAAs applicable to the CLB for the SLC/core ΔP lines at GGNS.

During the audit, the staff noted that the site documentation for the RV internals (RVI) program and inspection plan indicates that the design for the SLC/core ΔP penetration utilizes an Alloy 600 stub tube that is set into the bottom head and welded to an Alloy 600 housing. The staff also noted that the SLC/core ΔP nozzle and safe-end assembly form the reactor coolant pressure boundary (RCPB). In addition, the staff noted that LRA Table 4.3-2, “Cumulative Usage Factors for the Reactor Vessel,” includes a 40-year CUF for the SLC/core ΔP nozzle. Therefore, it was not clear to the staff why the CLB would not include an appropriate fatigue-based (i.e., CUF-based) TLAA that is applicable to the SLC/core ΔP penetration nozzle.

By letter dated April 3, 2012, the staff issued RAI B.1.8-3 requesting that the applicant provide additional information to clarify why the response to AAI No. 4 on the BWRVIP-27-A methodology did not identify any fatigue TLAA for the SLC/core ΔP nozzle. Specifically, the staff asked the applicant to resolve the conflict between the applicant's inclusion of the "liquid control- ΔP nozzle" in LRA Table 4.3-2 and the applicant's statement that the CLB did not include any CUF-based TLAA for the SLC/core ΔP nozzle. The staff further requested that the applicant clarify which component is specifically referred to by the "liquid control- ΔP nozzle" among the SLC/core ΔP penetration/nozzle and safe-end assembly. In addition, the applicant was requested to justify why the "liquid control-ΔP nozzle" is the representative component of the SLC/core ΔP penetration/nozzle and safe-end assembly for the fatigue TLAA.

In its response dated May 1, 2012, the applicant clarified that the ASME Code Class 1 RCPB for a BWR/6 Chicago Bridge and Iron Company-designed RV includes a stub tube that is set and welded into the RV bottom head at one end and is welded to a pressure boundary housing at its other end. The applicant further clarified that it is the nozzle that is identified as the "Liquid control-ΔP nozzle" vessel nozzle in LRA Table 4.3-2. The applicant also stated that the CUF value reported in LRA Table 4.3-2 for this nozzle represents the maximum (limiting) CUF that was identified for the nozzle assembly. The applicant further clarified that the applicant's SLC system injects through the CS system.

Based on this review, the staff finds that the applicant has adequately addressed AAI No. 4 on the BWRVIP-27-A methodology because the applicant confirmed that the applicant's SLC system injects through the CS system so that the SLC/core ΔP lines inside the reactor vessel do not have the function of distributing the SLC fluid. In addition, the applicant has appropriately identified a CUF-based TLAA for the core ΔP nozzle assembly as part of the reactor pressure vessel. The staff's evaluation regarding the fatigue TLAA of the reactor pressure vessel, which includes the core ΔP nozzle, is documented in Section 4.3.1.1. The staff's concern described in RAI B.1.8-3 is resolved.

<u>Operating Experience</u>. LRA Section B.1.8 summarizes operating experience related to the BWR Penetrations Program. The LRA states that visual inspections of the instrument penetrations and extensions were performed during 1996 to 2006 with no indications of degradation noted. The LRA also states that absence of aging effects indicates that the preventive actions of the program have been effective. The LRA further states that the BWR Penetrations Program detects aging effects using nondestructive examination (NDE) techniques to detect and characterize flaws. In addition, the applicant stated that these techniques are widely used and have been demonstrated effective at detecting aging effects during inspections performed to meet ASME Code Section XI requirements.

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 AMP 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 did not identify any operating experience events that might otherwise indicate that the applicant's program would not be effective in adequately managing cracking or other applicable 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.8 provides the UFSAR supplement for the BWR Penetrations Program. The staff reviewed this UFSAR supplement and needed additional information to confirm the adequacy of the summary description for the BWR Penetrations Program as described below.

SRP-LR, Table 3.0-1 includes an example of a UFSAR supplement summary description that may be used for AMPs that correspond to GALL Report AMP XI.M8, "BWR Penetrations." The summary description for the BWR Penetrations Program in SRP-LR Table 3.0-1 states that the program includes inspection and flaw evaluation in conformance with the guidelines of staff-approved BWR vessel and internals project documents BWRVIP-47-A, BWRVIP-49-A, and BWRVIP-27-A, to ensure the long-term integrity and safe operation of BWR vessel internal components.

In comparison, the applicant's summary description for the UFSAR supplement in LRA Section A.1.8 states that the BWR Penetrations Program manages cracking of BWR vessel penetrations using inspection and flaw evaluation activities, applicable industry standards, and staff-approved BWRVIP documents. The staff noted that, in contrast to the UFSAR supplement that is provided for these types of programs in SRP-LR Table 3.0-1, the applicant's UFSAR supplement summary description for its program did not include a specific reference to relevant BWRVIP documents that are applicable to the program. Thus, the staff found that the applicant's summary description for the UFSAR supplement may not be adequate to ensure the effectiveness of the program because of the omission of specific references to relevant BWRVIP documents for this program.

By letter dated April 3, 2012, the staff issued RAI B.1.8-2 requesting that the applicant justify why LRA Section A.1.8 (UFSAR supplement) did not reference the specific BWRVIP documents that are applicable to the implementation of the BWR Penetrations Program.

In its response dated May 1, 2012, the applicant stated that as stated in LRA Section B.1.8, the BWR Penetrations Program is consistent with the program described in GALL Report AMP XI.M8, BWR Penetrations, without an exception. The applicant also stated that therefore, by reference, the BWR Penetrations Program incorporates the relevant staff-approved BWRVIP documents, consistent with the GALL Report guidance. The applicant further stated that the BWRVIP-based program is an industry program that provides for implementation of guidelines for inspection, evaluation, repair, water chemistry, and other activities to support continued assurance of the structural integrity of BWR RCPB components. In addition, the applicant stated that as indicated in the July 29, 1997, letter from Brian W. Sheron (NRC) to Carl Terry (BWRVIP Chairman), the U.S. BWR fleet, including the applicant's unit, is committed to comply with BWRVIP guidelines.

In its review, the staff noted that the applicant clarified that its BWR Penetrations Program is consistent with GALL Report AMP XI.M8 without an exception so that the program incorporates the relevant staff-approved BWRVIP documents, consistent with the GALL Report. The staff found that this portion of the applicant's confirmation is adequate to ensure that the applicant's program is consistent with the GALL Report in terms of the use of the relevant staff-approved BWRVIP documents.

The staff noted that 10 CFR 54.21(d) requires that the UFSAR supplement contain a summary description of the programs and activities for managing the effects of aging. Without referencing specific BWRVIP documents credited for the BWR Penetrations Program, the staff could not determine whether the proposed UFSAR supplement in LRA Section A.1.8 contains an adequate summary description of the programs and activities for managing the effects of aging in accordance with 10 CFR 54.21(d).

By letter dated July 23, 2012, the staff issued RAI B.1.8-2a requesting that the applicant justify why LRA Section A.1.8 (UFSAR supplement) does not identify specific references to the BWRVIP documents credited for the applicant's BWR Penetrations Program.

In its response dated August 15, 2012, the applicant stated that LRA Section A.1.8 is revised to include a reference to BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49-A. In its response, the applicant also provided a corresponding revision to LRA Section A.1.8 (UFSAR supplement) that identifies BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49-A as BWR Penetrations Program reference documents. The staff finds the applicant's response acceptable because the applicant appropriately revised its UFSAR supplement to include specific references to the BWRVIP documents credited for the BWR Penetrations Program. Therefore, the UFSAR supplement for the BWR Penetrations Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAIs B1.8-2 and B1.8-2a is resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated August 15, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's BWR Penetrations 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 through Commitment No. 33 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 BWR Stress Corrosion Cracking Program

Summary of Technical Information in the Application. LRA Section B.1.9 describes the existing BWR Stress Corrosion Cracking Program as consistent, with an exception, with GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking." The LRA states that the BWR Stress Corrosion Cracking Program is an existing program that manages cracking of the RCPB through the implementation of applicable preventive measures, inspection, and flaw evaluation program element criteria. The LRA also states that the program accomplishes its objectives through the implementation of staff-approved BWRVIP documents and the applicant's response bases to NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," Revision 2, issued 1998, and NRC GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," issued January 1988, and Supplement 1 to 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 one through six 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 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.M7 identifies 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.

During the audit, the staff noted that the site documentation, including the applicant’s report to evaluate AMP consistency, indicates that the applicant’s program includes the relevant piping and piping welds regardless of code classification. The staff noted that LRA Section B.1.9 states that the BWR Stress Corrosion Cracking Program is an existing program that manages cracking of the RCPB through the implementation of applicable preventive measures, inspection, and flaw evaluation criteria. In addition, LRA Table 3.1.2-3 for the RCPB components indicates that the applicant credited the BWR Stress Corrosion Cracking Program to manage the aging effect of RCPB components only.

Therefore, the staff could not determine whether the scope of the applicant’s BWR Stress Corrosion Cracking Program includes the relevant piping and piping welds regardless of ASME Code classification, consistent with the GALL Report. Specifically, the staff noted that the LRA appeared to include only ASME Code Class 1 RCPB components in the program scope, but did not clearly address whether the scope of the program includes non-Class 1 piping and associated piping welds.

By letter dated April 3, 2012, the staff issued RAI B.2.1.9-1 requesting that the applicant clarify whether the scope of the BWR Stress Corrosion Cracking Program includes non-Class 1 piping and piping welds made of austenitic stainless steel and nickel alloy materials, consistent with GALL Report AMP XI.M7. The staff also requested that if the scope of the AMP did not include non-Class 1 piping, for the applicant to justify why non-Class 1 piping and piping welds were excluded from the scope of the applicant’s program. The staff further requested that if the scope of the program did include non-Class 1 piping and associated piping welds, that the applicant revise LRA Sections B.1.9 and A.1.9, as necessary, to clarify that the scope of the program includes the relevant piping and piping welds regardless of code classification.

In its response dated May 1, 2012, the applicant clarified that the BWR Stress Corrosion Cracking Program applies to relevant BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of code classification, consistent with the GALL Report as described in LRA Section B.1.9. The applicant also clarified that non-Class 1 piping and piping welds were not excluded from the program and that, at GGNS, all components included in the scope of this AMP are part of the RCPB. The applicant further indicated that the results of the AMR of these RCPB components are documented in LRA Tables 3.1.2-1 and 3.1.2-3.

In its review, the staff noted that LRA Section 2.3.1.2 addresses the scoping of the RCPB and indicates that the components in the RCPB are classified as ASME Code Class 1 components. LRA Section 2.3.1.2 also indicates that the majority of the components that comprise the applicant’s RCPB are from the nuclear boiler and reactor recirculation systems and that the RCPB also includes the Class 1 portions of other systems. In addition, LRA items 3.2.1-54 and 3.3.1-110 indicate that the components in the ESF systems and auxiliary systems within the scope of the BWR Stress Corrosion Cracking Program were reviewed as part of the RCPB. Therefore, the staff needed to confirm whether the program scope adequately includes RCPB components and other non-Class 1 components, consistent with the GALL Report.

By letter dated July 23, 2012, the staff issued RAI B.1.9-1a requesting that the applicant justify why LRA Sections B.1.9 and A.1.9 indicate that the BWR Stress Corrosion Cracking Program manages only aging of the RCPB rather than the scope of the program recommended in the GALL Report that includes relevant piping and piping welds regardless of code classification. The staff also requested that the applicant clarify why LRA items 3.2.1-54 and 3.3.1-110 indicate that the components in the ESF systems and auxiliary systems, subject to the program, were reviewed as part of the RCPB rather than against the relevant stainless steel and nickel alloy piping and piping welds, regardless of code classification. The staff further requested that, if necessary, the applicant provide updates to LRA Sections B.1.9 and A.1.9 and LRA AMR items 3.2.1-54 and 3.3.1-110, consistent with the applicant's response to RAI B.1.9-1a.

In its response dated August 15, 2012, the applicant stated that there are no piping components or piping welds made of austenitic stainless steel or nickel alloy that are 4 inches or larger in nominal diameter and contain reactor coolant at a temperature above 93°C (200°F) during power operation in the non-Class 1 portions of the ESF and auxiliary systems (i.e., outside the reactor coolant pressure boundary). The applicant also provided revisions to LRA Sections A.1.9 and B.1.9 to delete the reference to reactor coolant pressure boundary and to add reference to relevant piping and welds regardless of code classification. The applicant further provided revisions to LRA items 3.2.1-54 and 3.3.1-110 to clarify that there are no components outside the reactor coolant pressure boundary subject to the BWR Stress Corrosion Cracking Program requirements.

In its review, the staff finds the applicant's basis, as amended in the response to RAI B.1.9-1a, to be acceptable because the applicant clarified that the non-Class 1 portions of the ESF and auxiliary systems do not include a stainless steel or nickel alloy piping component that should be included within the scope of BWR Stress Corrosion Cracking Program and the applicant's program includes all the relevant piping and piping welds in the scope of the program. The staff also finds that the applicant's revisions to LRA Sections A.1.9 and B.1.9 and items 3.2.1-54 and 3.3.1-110 are appropriate, consistent with the acceptable response of the applicant. The staff's concern described in RAIs B1.9-1 and B.1.9-1a is resolved.

During the audit, the staff noted that the site documentation for AMP's consistency evaluation indicates that the applicant's "detection of aging effects" program element is credited to manage cracking of stainless steel and nickel alloy piping and piping welds and the following additional stainless steel or nickel alloy components: (a) stainless steel thermal sleeves and nickel alloy thermal sleeve extensions of RV nozzles (recirculation inlet, CS inlet, and RHR/low-pressure coolant injection (LPCI) nozzles), and (b) stainless steel pump casings, valve bodies, and thermowells.

In its review, the staff noted that the guidance of GALL Report AMP XI.M7 for selection of IGSCC-resistant materials is applied to the components described above. The staff also noted that the inspections described in GALL Report AMP XI.M7 are mainly based on the guidance in GL 88-01 that addresses inspections of piping and piping welds. Therefore, it was not clear to the staff what types of inspections would be performed on the stainless steel thermal sleeves and nickel alloy thermal sleeve extensions for the recirculation inlet, CS inlet, and RHR/LPCI nozzles and on stainless steel pump casings, valve bodies, and thermowells as part of the applicant's BWR Stress Corrosion Cracking Program.

By letter dated April 3, 2012, the staff issued RAI B.1.9-2 requesting the applicant to identify the types of inspections performed on the following components in accordance with the applicant's BWR Stress Corrosion Cracking Program: (1) stainless steel thermal sleeves and nickel alloy thermal sleeve extensions of RV nozzles (recirculation inlet, CS inlet, RHR/LPCI nozzles), and (2) stainless steel pump casings, valve bodies, and thermowells. The staff also requested that the applicant identify the inspection methods, sample sizes, and inspection frequencies that would be applied to the inspections of these components during the period of extended operation. The staff further requested that the applicant justify why inspection methods, sample sizes, and inspection frequencies selected are considered to be capable of detecting and managing cracking in the components during the period of extended operation.

In its response dated May 1, 2012, the applicant clarified that the applicant selects components and piping for examination based on the staff-approved inspection schedule and methods described in BWRVIP-75-A. The applicant also clarified that welds adjacent to specific components are inspected because welds are the susceptible areas. In addition, the applicant stated that the program specifies that these welds shall be volumetrically examined using a UT examination method. In its review of the applicant's response to RAI B.1.9-2, the staff finds that this portion of the applicant's response is adequate to manage cracking due to SCC of the pump casings, valve bodies, thermowells, and their adjacent welds in scope of the program because the program examines the adjacent welds of these components, consistent with the GALL Report.

The staff noted that GALL Report item IV.B1.R-99 recommends the BWR Vessel Internals Program and Water Chemistry Program to manage cracking of the CS nozzle thermal sleeves. In addition, Section 3.2.4, "Other Locations," of BWRVIP-18-A, "BWR Vessel and Internals Project BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines," indicates that there is currently no technique available for inspecting the CS nozzle thermal sleeve welds. BWRVIP-18-A further indicates that inspection of thermal sleeve welds should be done when the capability exists. Therefore, it was not clear to the staff how the applicant's BWR Stress Corrosion Cracking Program inspects the thermal sleeves and thermal sleeve extensions to manage cracking due to SCC and IGSCC.

In addition, the LRA does not include an AMR item for aging management of CS nozzle thermal sleeves, based on GALL Report item IV.B1.R-99. The staff needed to further clarify whether the BWR Vessel Internals Program (including BWRVIP-18-A) is used to manage cracking of the CS nozzle thermal sleeves, consistent with the GALL Report.

By letter dated July 23, 2012, the staff issued RAI B.1.9-2a requesting that the applicant provide justification for using the BWR Stress Corrosion Cracking Program to manage the aging of thermal sleeves and thermal sleeve extensions, given that they are typically located within the RV or piping. The staff also requested that as part of the justification, the applicant describe how the BWR Stress Corrosion Cracking Program inspects these components (for example, using UT). In addition, the staff requested that the applicant describe the inspection results and operating experience in terms of occurrence of cracking in the thermal sleeves and sleeve extensions of the reactor nozzles.

In its response, the applicant stated that the thermal sleeves for the recirculation inlet, core spray inlet, and RHR/LPCI nozzles are, in part, formed by the internal leg of the Y-shaped safe ends for those nozzles. The applicant also stated that the thermal sleeves are welded to the safe end and extend into the vessel. The applicant further stated that the welds connecting the safe ends to the vessel nozzles and external piping are RCPB welds and the BWR Stress Corrosion Cracking and Water Chemistry Control - BWR Programs are credited to manage cracking of these safe end pressure boundary welds as evaluated in LRA Table 3.1.2-1.

In addition, the applicant stated that the components represented by the lines in LRA Table 3.1.2-1 for the thermal sleeves and extensions include the thermal sleeves starting from the weld to the safe end and extending inward. The applicant stated that the thermal sleeves, starting from the weld to the safe end, are within the scope of the BWR Vessel Internals Program. In its response, the applicant also revised LRA Table 3.1.2-1 to indicate that the BWR Vessel Internals and Water Chemistry Control - BWR Programs are used to manage cracking of the thermal sleeves and thermal sleeve extensions.

The staff finds that the applicant's proposal of using the BWR Vessel Internals Program to manage cracking in these thermal sleeve components is consistent with the scope of GALL Report AMP XI.M9, "BWR Vessel Internals." SER Section 3.0.3.1.10 documents the staff's evaluation regarding the applicant's aging management for the thermal sleeve components using the BWR Vessel Internals Program. The staff's concern described in RAI B.1.9-2a is resolved.

As part of its response to RAI B.1.9-2, the applicant also identified the use of its risk-informed inspection methodology as an exception to the "detection of aging effects" program element of GALL Report AMP XI.M7. The staff reviewed the portions of the "detection of aging effects" program element associated with the exception to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception follows.

<u>*Exception*</u>. By letter dated May 1, 2012, the applicant amended LRA Sections B.1.9 and A.1.9, and identified an exception to the "detection of aging effects" program element. In this exception, the applicant stated that its BWR Stress Corrosion Cracking Program uses inspection frequencies established in BWRVIP-75-A, Table 3-1, except those for Category A welds that are examined in accordance with the risk-informed inservice inspection (RI-ISI) application. The applicant also stated that the use of an RI-ISI application for Category A welds is justified because the risk-informed application was authorized by the staff in a 2007 SER. The applicant further stated that this SER allowed the applicant to use a risk-informed approach in selecting components for inservice inspection (ISI) based on ASME Code Case N-716.

In its review, the staff noted that the NRC letter, dated September 21, 2007, states that the staff authorizes the proposed alternative in accordance with 10 CFR 50.55a(a)(3)(i) for the remainder of the licensee's second 10-year ISI interval and for its third 10-year ISI interval ending in 2017. The NRC letter also states that the staff's approval of the licensee's risk-informed inspection program does not constitute approval of ASME Code Case N-716.

As described above, the staff noted that the NRC approval for the applicant's use of the ASME Code Case N-716 methodology, modified as described by the applicant's previous submittals, is granted for a certain portion of the second ISI interval and the third interval only. If the applicant further pursues the continued use of its risk-informed inspection methodology, the applicant would be required to reapply for the use of its risk-informed methodology for any 10-year interval beyond the third interval, including the fifth and sixth 10-year intervals for the period of extended operation. Therefore, the staff needed clarification of the inspection scope and schedule the applicant would use in the BWR Stress Corrosion Cracking Program in the case the applicant could not get NRC approval for the use of the applicant's risk-informed methodology.

By letter dated July 23, 2012, the staff issued RAI B.1.9-3 requesting that the applicant clarify what inspection scope and schedule the BWR Stress Corrosion Cracking Program would use for Category A welds in the case the applicant could not get NRC approval for the use of the applicant's RI-ISI methodology. The staff also requested that the applicant ensure that LRA Sections B.1.9 and A.1.9 are consistent with the applicant's response.

In its response dated August 15, 2012, the applicant indicated that in the case that GGNS could not get NRC approval for the use of the RI-ISI methodology, the BWR Stress Corrosion Cracking Program will use the inspection scope and schedule, which are described in BWRVIP-75-A, for the Category A welds. The applicant also provided revisions to LRA Sections A.1.9 and B.1.9 accordingly. In its review, the staff finds that the applicant's basis, as amended in the RAI response, acceptable because the applicant's amended basis is consistent with GALL Report AMP XI.M7 and the applicant appropriately revised the LRA. The concern described in RAI B.1.9-3 is resolved.

Summary. Based on its audit and review of the applicant's responses to RAIs B.1.9-1, B.1.9-2, B.1.9-3, B.1.9-1a, and B.1.9-2a of the applicant's BWR Stress Corrosion Cracking Program, the staff finds that program elements one through six 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 also reviewed the exception associated with the "detection of aging effects" program element, and its justification and finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.9 summarizes operating experience related to the BWR Stress Corrosion Cracking Program. The LRA states that a review of Owner's Activity Reports for 2004 through 2009 showed no indications of cracking from inspections performed under this program and the absence of aging effects indicates that the preventive actions of the program have been effective.

The staff reviewed operating experience information in the LRA 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 AMP 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, resulting in the issuance of an RAI, as follows. Event Notification Report No. 47880, dated April 30, 2012, indicates that the applicant detected an unacceptable flaw by UT in one of the RHR system to reactor pressure vessel (RPV) nozzles (N06B-KB weld) during the refueling outage. The dimension of the indication is approximately 0.9 inch in length and approximately 0.5 inch in depth. Nominal wall thickness of the weld is 1.3 inches.

The event notification also indicates that the flaw has been evaluated by Entergy Engineering and determined to meet the criteria for reporting as identified in NUREG-1022, "Event Reporting Guidelines: 10 CFR 50.72 and 50.73": welding or material defects in the primary coolant system that cannot be found acceptable under ASME Code Section XI, IWB-3600, "Analytical Evaluation of Flaws," or ASME Code Section XI, Table IWB-3410-1, "Acceptable Standards." Therefore, the staff needed to further confirm that this operating experience does not affect the effectiveness of the applicant's BWR Stress Corrosion Cracking Program.

By letter dated July 23, 2012, the staff issued RAI B.1.9-4 requesting that the applicant clarify whether the weld addressed in Event Notification Report No. 47880 is included in the scope of the BWR Stress Corrosion Cracking Program. The staff also requested that the applicant identify the category of the weld in accordance with the IGSCC categories defined in GL 88-01. In addition, the staff asked the applicant to evaluate the data from this operating experience event in terms of its impact on the effectiveness of the applicant's BWR Stress Corrosion Cracking Program, as follows:

- describe the results of the previous inspections performed on this weld (N06B-KB weld) as part of the BWR Stress Corrosion Cracking Program
- describe the root or apparent cause analysis results and the corrective action to be taken. In addition, identify the new weld category assigned after this event to confirm whether it is consistent with GL 88-01 as referenced in GALL Report AMP XI.M7
- justify why this operating experience does not affect the effectiveness of the applicant's program. As part of the response, identify any impact of this operating experience on the program elements of the applicant's BWR Stress Corrosion Cracking Program

In its response dated August 15, 2012, the applicant stated the N06B nozzle connects the residual heat removal C system to the RPV and the weld N06B-KB is included in the scope of the BWR Stress Corrosion Cracking Program. The applicant also stated that the 2012 examination was performed to comply with BWRVIP-75-A for Category C welds. The applicant further stated that the Category C N06B-KB weld (RHR/LPCI inlet nozzle to safe end weld) is constructed of the following materials. The nozzle material is carbon steel A-508 Class 2. The safe end material is Inconel SB-166, which is considered Alloy 600. The weld butter is Inconel 182 weld metal. The weld is Inconel 82/182 weld metal.

In its response regarding the previous inspections, the applicant stated that prior to 2012, no IGSCC type indication had been observed in the N06B nozzle and previous exams were limited on the downstream side of the N06B-KB weld (nozzle side) due to the nozzle configuration, especially when performing a circumferential scan looking for axial flaws. The applicant also stated that the circumferential scan was limited due to the weld crown and nozzle configuration. The applicant further stated that during 2012, this nozzle received extensive weld crown reduction and surface preparation which enabled the examination to detect the subject flaw. In addition, the applicant stated that in 1990, an induction heating stress improvement (IHSI) process was performed on all DM welds to perform stress relieving and prevent or mitigate the occurrence of nozzle cracks, including those in the N6B nozzle. The applicant stated that a post-UT examination was completed after the IHSI process and no indications were identified in the N6B nozzle weld. The applicant also stated that however, as noted earlier, it did not perform any circumferential scan of the downstream side of the weld due to its design configuration.

In its response regarding the root cause analysis and corrective actions, the applicant stated that the apparent cause of the weld indication is that the weld and weld butter were fabricated with Inconel materials susceptible to IGSCC and in 1990, actions were taken to mitigate this condition through implementation of an IHSI process. The applicant also stated that after discovery of the weld indication in 2012, the weld was repaired by weld overlay. The applicant further stated that prior to this event, the weld was categorized as a Category C weld, as defined in BWRVIP-75-A and that future inspections of this weld will be conducted per BWRVIP-75-A for Category E welds, consistent with BWRVIP-75-A. In its review, the staff noted that the applicant appropriately identified IGSCC Category E for the N06B-KB weld because BWRVIP-75-A categorizes a cracked weld, which has been reinforced by weld overlay, as Category E.

The applicant also stated that BWRVIP-61, "Induction Heating Stress Improvement Effectiveness on Crack Growth in Operating Plants," documents the results of an investigation into the most likely causes for post-IHSI-process IGSCC, and per the report, cracking reported after IHSI can be attributed to existing cracking that initially went undetected following application of IHSI. The applicant stated that the flaws existed at the time of IHSI treatment, but were later detected with better examination methods and better trained personnel.

In its response regarding the effectiveness of the applicant's program, the applicant indicated that due to industry concerns with cracking in DM welds, the industry committed to an accelerated inspection program provided in BWRVIP-222, "Accelerated Inspection Program for BWRVIP-75-A Category C Dissimilar Metal Welds Containing Alloy 182," July 2009. The applicant also stated that 20 DM Category C welds were inspected prior to 2012 to comply with the BWRVIP-222 requirements, and the remaining 14 welds in the program were inspected during 2012. The applicant further stated that all BWRVIP-75-A Category C welds have been inspected and the N06B nozzle was the last nozzle requiring inspection.

In addition, the applicant indicated that its BWR Stress Corrosion Cracking Program is based upon the guidelines of BWRVIP-75-A, and since GL 88-01 was issued, the BWR industry has performed several thousand weld examinations on piping subject to the GL requirements. The applicant also indicated that during this time, the industry has improved the water chemistry of reactor coolant thereby reducing initiation and growth of IGSCC, stress improvement has also been employed as an IGSCC remedy, and the examination procedures have been, and continue to be, improved. The applicant further stated that the detection of this indication as described above demonstrates the effectiveness of the program in identifying IGSCC using today's improved inspection techniques and procedures so that this operating experience has no impact on the program elements of the applicant's BWR Stress Corrosion Cracking Program.

The staff found that portions of the applicant's response were acceptable because the applicant clarified that (a) IGSCC Categories has been appropriately assigned to the N06B-KB weld based on the materials of the weld, mitigation actions, and operating experience, consistent with GL 88-01 and BWRVIP-75-A, so that inspections will be performed on the weld, consistent with GALL Report AMP XI.M7, (b) as a corrective action in response to the detection of the indication, the weld was repaired by weld overlay, which is also consistent with the GALL Report, (c) the previous issue with the limited inspection coverage of the weld was resolved by the weld crown reduction and surface preparation so that the flaw could be detected in the inspections, and (d) the applicant complies with the BWRVIP-222 requirements, consistent with the industry commitment. The staff identified its concerns as follows.

The applicant's response did not provide justification for why the implementation of the accelerated inspections, which are specified in BWRVIP-222, is not identified as an enhancement to the existing BWR Stress Corrosion Cracking Program. In addition, the staff needed to confirm whether any other welds in the scope of the program have limited inspection coverage as was the case with the N06B-KB weld prior to the weld crown reduction. By letter dated October 3, 2012, the staff issued RAI B.1.9-4b requesting applicant's clarification for these items.

In its response dated October 22, 2012, the applicant stated that during the refueling outage in 2012, the applicant completed its UT of all Category C DM welds, as performed in accordance with the accelerated inspection schedule of BWR-222, Section 9. The applicant also stated that the use of BWRVIP-222 is not an enhancement to the BWR Stress Corrosion Cracking Program because none of the applicant's Category C DM welds will require an accelerated inspection per BWRVIP-222 for the period of extended operation.

In addition, the applicant stated that two Category C welds in the scope of the applicant's program have limited inspection coverage because inspections of these welds could not achieve the 90 percent-by-volume inspection coverage criterion specified in ASME Code Case N-460. The applicant clarified that the reduced inspection coverage for the welds is due to the concavities on the outer weld surfaces that cannot result in reliable UT signals, but that the volumetric inspection coverage for each of these two welds is at least 75 percent. The staff finds that the applicant's basis for aging management, as clarified in its response of October 22, 2012, is acceptable because the applicant does not have any additional accelerated inspection to be performed per BWRVIP-222 and the inspection coverage of at least 75 percent for the two Category C welds provides reasonable assurance cracking in these two welds will be detected and the structural integrity of the welds will be maintained. The concern described in RAI B.1.9 -4b is resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.9 provides the UFSAR supplement for the BWR Stress Corrosion Cracking Program. The staff reviewed this UFSAR supplement to determine whether the UFSAR supplement includes an adequate description for the program. In its initial review, 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 related to its UFSAR supplement.

As addressed in the staff's evaluation related to RAI B.1.9-1a, the staff requested that the applicant justify why LRA Section A.1.9 indicates that the BWR Stress Corrosion Cracking Program manages only aging of the RCPB rather than the scope of the program recommended in the GALL Report that includes the relevant piping and piping welds regardless of code classification.

As described in the sections above, the applicant's response to RAI B.1.9-1a confirms that there are no piping components or piping welds made of austenitic stainless steel or nickel alloy that are 4 inches or larger in nominal diameter and contain reactor coolant at a temperature above 93°C (200°F) during power operation in the non-Class 1 portions of the ESF and auxiliary systems. The applicant also provided revisions to LRA Sections A.1.9 (UFSAR supplement) to delete the reference to reactor coolant pressure boundary and to add the reference to relevant piping and welds regardless of code classification.

In its review, the staff finds the applicant's response acceptable because the applicant confirmed that all the relevant piping and piping welds included in the scope of the program are Class 1 components so that the non-Class 1 portions of the ESF and auxiliary systems do not have a component in the program scope. The staff also finds that the applicant's revisions to LRA Section A.1.9 (UFSAR supplement) are appropriate and consistent with the applicant's description in its response. The staff's concern described in RAI B.1.9-1a is resolved. The staff finds that the information in the UFSAR supplement, as amended by letter dated August 15, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's BWR Stress Corrosion Cracking 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.M7. In addition, the staff reviewed the program exception and its justification and determines that the AMP, with the program exception, is adequate to manage the applicable aging effects. 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 BWR Vessel Inside Diameter (ID) Attachment Welds

Summary of Technical Information in the Application. LRA Section B.1.10 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 RV 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 RV internal attachment welds.

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.M4.

In particular, the staff confirmed that the AMP addresses the inspection of the welds in accordance with ASME Code Section XI, Subsection IWB, Examination Category B-N-2. The staff also confirmed that the inspection schedule is in accordance with ASME Code Section XI, Subsection IWB-2400, and Table 3-2 of the BWRVIP-48-A, consistent with the recommendation of GALL Report AMP XI.M4. 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, IWA-4000.

Based on its audit of the applicant's BWR Vessel ID Attachment Welds Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M4.

Operating Experience. LRA Section B.1.10 summarizes operating experience related to the BWR Vessel ID Attachment Welds Program.

The applicant indicated that the examinations of vessel internal attachment welds were performed using EVT-1 visual techniques. The applicant stated that the examinations included piping welds, piping brackets, and jet pump riser brace attachment welds. The applicant stated that visual examinations were performed on 16 CS brackets, and a tack weld on a bolt was identified as cracked. The applicant explained that the condition was found to be acceptable and the inspection interval for the bolt was shortened from every fourth refueling outage to each refueling outage. The applicant further stated that inspection of jet pump wedges and jet pump weld locations were performed using visual examination and no indications were identified. Examinations of the steam dryer support and holddown attachment welds were performed and no indications were 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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.10 provides the UFSAR supplement for the BWR Vessel ID Attachment Welds Program. The staff reviewed the UFSAR supplement description of the program, which stated that applicable industry standards and staff-approved BWRVIP documents are used to delineate the program. The staff noted that the summary does not identify the use of the BWRVIP-48-A report, which is recommended by GALL Report AMP XI.M4. By letter dated April 3, 2012, the staff issued RAI B.1.10-1 requesting the applicant revise LRA Section A.1.10 to reference the use of the BWRVIP-48-A report, or justify its exclusion. In its response dated May 1, 2012, the applicant stated that LRA Section A.1.10 was not changed to include the reference of BWRVIP-48-A. The applicant stated that the Section A.1.10 reference "applicable industry standards and staff-approved BWRVIP documents" provides a more comprehensive definition of applicant guidance to ensure program effectiveness than to list only specific BWRVIP documents that may be revised or superseded in the future. However, the staff noted that this is inconsistent with SRP-LR Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," for GALL Report AMP XI.M4, which specifically references BWRVIP-48-A.

By letter dated July 23, 2012, the staff issued follow-up RAI B.1.10-1a requesting the applicant revise LRA Section A.1.10 to indicate that the BWR Vessel Attachment Welds Program perform inspections and flaw evaluation in accordance with the guidelines in the BWRVIP-48-A report.

In its response dated August 15, 2012, the applicant revised LRA Sections A.1.10 and B.1.10 to include a reference to BWRVIP-48-A. The staff finds the applicant's response to RAI B.1.10-1a acceptable because the revised LRA Section A.1.10 is an accurate summary description of the program and activities for managing the effects of cracking in the reactor vessel ID attachment welds, consistent with SRP-LR. The staff's concerns identified in RAIs B.1.10-1 and B.1.10-1a are resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated August 15, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's 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).

3.0.3.1.10 BWR Vessel Internals

Summary of Technical Information in the Application. LRA Section B.1.11 describes the existing BWR Vessel Internals Program as consistent, with an enhancement, with GALL Report AMP XI.M9, “BWR Vessel Internals.” The applicant stated that this program includes inspection, flaw evaluation and repair guidelines that are consistent with the guidelines addressed in relevant BWRVIP reports. No exceptions are taken by the applicant; and there is one enhancement, which affects the “detection of aging effects” program element. The enhancement will first evaluate the susceptibility to thermal and/or neutron embrittlement of cast austenitic stainless steel (CASS), X-750 alloy, precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel), and martensitic stainless steel (e.g., 403, 410, 431 steel). Collectively, these corrosion-resistant materials are referred to as the “subject, other corrosion-resistant materials” in the remainder of this section.

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 elements of GALL Report AMP XI.M31. For the “scope of program,” ”detection of aging effects,” and “monitoring and trending,” program elements, sufficient information was not available to determine whether they were consistent with the corresponding program elements of the GALL Report AMP. In order to obtain the information necessary to verify whether these program elements are consistent with the corresponding program elements of the GALL Report AMP, the staff issued the following RAIs.

The “scope of program” program element of GALL Report AMP XI.M9 recommends listing all of the relevant documents associated with the AMP. During its audit, the staff found that the applicant’s BWR Vessels Internals AMP states “Applicable industry standards and staff-approved BWRVIP documents are used to delineate the program.” By letter dated June 27, 2012, the staff issued RAI B.1.11-1 requesting that the applicant explain why an explicit list of BWRVIP programs is not provided.

In the July 25, 2012, response to RAI B.1.11-1, the applicant provided justification for why an explicit list is not necessary and proposed to modify LRA Section A.1.11 to emphasize that the scope of the GGNS Vessel Internals Program will comply with all BWRVIP guidelines. The staff has reviewed the applicant’s response and finds the applicant’s position and modification to Section A.1.11 acceptable because the applicant provided an explicit statement regarding the scope of the program. This resolves the issue related to RAI B.1.11-1.

The “monitoring and trending” program element of GALL Report AMP XI.M9 considers that each BWRVIP guideline recommends appropriate fracture toughness values to be used in flaw evaluations. However, during its audit, the staff found that LRA Appendix C references BWRVIP-76-A for core shroud flaw evaluations. By letter dated June 27, 2012, the staff issued RAI B.1.11-3 asking if the applicant will use the more conservative lower bound fracture toughness value reported in BWRVIP-100-A or the less conservative values found in BWRVIP-76-A for flaw evaluations of defects found in core shroud welds.

In the July 25, 2012, response to RAI B.1.11-3, the applicant stated, “the GGNS BWR Vessel Internals Program uses the appropriate toughness versus fluence relationships and flaw evaluation methods from BWRVIP-100-A, for irradiated stainless steel reactor internals where applicable."

The staff has reviewed the response and is no longer concerned that there could be confusion related to which fracture toughness value to use for the "monitoring and trending" activities. This resolves the issue related to RAI B.1.11-3.

The "scope of program" program element of GALL Report AMP XI.M9 includes BWRVIP-139 as one of the relevant documents. However, during its audit, the staff found that, as part of the extended power uprate (EPU) at GGNS, the applicant has a new steam dryer. By letter dated June 27, 2012, the staff issued RAI B.1.11-4 requesting that the applicant describe the new steam dryer and if it is within the scope and bounding criteria of the BWRVIP-139-A report.

In the applicant's July 25, 2012, response to RAI B.1.11-4, the applicant stated:

> 1. BWRVIP-139-A provides broad inspection guidelines based on the general characteristics of the various dryer configurations, without establishing bounding criteria that would exclude dryers of similar design. A description of the new steam dryer was included in Attachment 11 B to GNRO-201 0/00056, License Amendment Request, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1, and dated September 8, 2010. Like the original dryer, the new dryer is a curved hood sixbank design. The inspection requirements of BWRVIP-139-A are directly applicable to the GGNS replacement steam dryer.
> 2. As described in the response to RAI 8, part b, in Attachment 1 of GNRO-2011/001 01, Request for Additional Information Regarding Extended Power Uprate Grand Gulf Nuclear Station, Unit 1, dated November 14, 2011, Entergy plans to follow the inspection recommendations of BWRVIP-139 Section 5.3.3 for curved hood steam dryers, and the re-inspection guidelines of Section 5.3.4.
>
>   In GNRO-2012/00031, Supplemental Information - License Conditions, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1, dated April 26, 2012, Entergy proposed license condition 46 which included the following.
>
>   (f) During the first two scheduled refueling outages after reaching full EPU conditions, Entergy shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines. Entergy shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup.
>
>   (g) At the end of the second refueling outage following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval.
>
>   Consistent with GALL Report AMP XI.M9, steam dryer inspection and evaluation will be based on BWRVIP-139-A. Following the second refueling outage after implementation of the extended power uprate, the BWRVIP-139-A

> recommendations will be supplemented by any additional inspection requirements determined for the long-term steam dryer inspection plan submitted for NRC review and approval in accordance with License Condition 46 part (g). Consequently, GGNS LRA Section B.1.11 need not be modified to include an exception. GGNS LRA Section A.1.11 is modified to note the supplementary steam dryer inspection requirements that may result from License Condition 46 part (g).

The staff has reviewed the response and considers that the details do support the use of BWRVIP-139-A for guidance on the inspection and evaluation of any flaws discovered in the new steam dryer. The interim requirements associated with License Condition 46 for the EPU do not change the AMP for the period of extended operation. The modification to LRA Section A.1.11, reflecting the information provided in this RAI response, is acceptable. This resolves the issue related to RAI B.1.11-4.

The staff also reviewed the portions of the "detection of aging effects," program element associated with the one enhancement to determine whether the program will adequately manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B.1.11 states an enhancement to the "detection of aging effects," program element. This enhancement has two parts. In the first part, the applicant will evaluate the susceptibility of the subject materials and other corrosion resistant materials used for the RV internal components, to assess the loss of fracture toughness for the material due to thermal embrittlement, neutron embrittlement, and any synergistic effects of the two aging mechanisms. In the second part, suitable inspection procedures will be developed to address the susceptible components. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M9 and determined the need for additional information.

The "detection of aging effects" program element of GALL Report AMP XI.M9 states that portions of the susceptible components determined to be limiting will be inspected as part of the 10-year ISI program during the period of extended operation. Furthermore, the sample size should be 100 percent of the accessible component population, excluding components that may be in compression during normal operations. However, during the staff's review of the enhancement, the staff found that the description of the enhancement to the applicant's BWR Vessels Internals AMP could be taken to be a sampling-based, condition monitoring program where 100 percent of the accessible and susceptible components would not be inspected. By letter dated June 27, 2012, the staff issued RAI B.1.11-2 requesting (1) information on which materials, other than austenitic stainless steel, are used in the RVI components exposed to a neutron fluence of $1x10^{17}$ n/cm^2 (E > 1 MeV), and (2) more details of how the enhancement will help to manage the loss of fracture toughness so that the nature of the enhancement can be verified by a future license renewal audit.

In response to RAI B.1.11-2, dated July 25, 2012, the applicant stated:

> The enhancement stated in LRA Section B.1.11, BWR Vessel Internals, for the management of loss of fracture toughness due to neutron irradiation and thermal aging embrittlement is consistent with the guidance provided in NUREG-1801, Rev. 2, Section XI.M9, BWR Vessel Internals. This guidance establishes the overall parameters of this aspect of the BWR Vessel Internals Program. Details of this aspect of the program remain to be determined, including:

a. the specific scope of components susceptible to neutron irradiation and thermal aging embrittlement,

b. the inspection techniques to be used,

c. sequence of inspections to be conducted, and

d. the methods for evaluating inspection results and extrapolating those results to inaccessible components.

These details will be developed as part of the implementation of the program enhancement described in LRA B.1.11. No revisions to UFSAR Supplement A.1.11 are warranted.

Based on its review of the applicant's response, the staff needed additional information to find the applicant's program acceptable. In a letter dated October 17, 2012, the staff issued a follow-up RAI B.1.11-2a where the staff requested the applicant to address the following items:

a. description of the components made from CASS, X-750 alloy, PH martensitic stainless steel, and martensitic stainless steel, and other corrosion resistant materials that are exposed to the reactor coolant and neutron flux environment

b. description of the sample size for the initial inspection of susceptible components; if only portions of susceptible components will be inspected, provide justification

c. clarification regarding the frequency off the augmented inspections

In the November 15, 2012, response to RAI B.1.11-2a, the applicant provided a revision of the enhancement to include a list that identifies components of the subject material and other corrosion resistant materials, along with revised wording to reflect that the initial sample size will be 100 percent of the susceptible components. The applicant confirmed that the intent is for the augmented inspection to be a one-time inspection unless the results of the initial inspections at GGNS and other industry experience identify a need for additional/periodic inspections.

The staff has reviewed the applicant's response to RAI B.1.11-2a and finds the response acceptable because Entergy Nuclear participates in the BWRVIP and GGNS has committed to follow all updated guidance on the need for and timing of future inspections. This resolves the issues related to RAI B.1.11-2a.

By letter dated August 15, 2012, the applicant provided a response to RAI B.1.9-2a that amended the LRA and indicated that the BWRVIP, along with the Water Chemistry Control - BWR Program, is credited to manage cracking due to SCC and IGSCC in the thermal sleeves and thermal sleeve extensions of the RV nozzles. The applicant also stated the recirculation inlet, CS inlet, and RHR/LPCI nozzles are in part, formed by the internal leg of the Y-shaped safe ends for those nozzles.

As described in Appendix C of the LRA, the applicant's response to Action Item No. 5 of BWRVIP-42-A states that the BWRVIP has developed strategies to ensure the integrity of inaccessible welds [associated with the LPCI nozzle and thermal sleeve]. The applicant also stated that these strategies are included in Section 3 of BWRVIP-42, Revision 1, and it has committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation.

In its review, the staff noted that the applicant's AMR items for the thermal sleeve components in LRA Table 3.1.2-1 do not include the thermal sleeve and thermal sleeve extension of the reactor vessel feedwater nozzle. In addition, neither the LRA or applicant's RAI response provide a clear description of the “strategies” in BWRVIP-42, Revision 1, to manage the inaccessible thermal sleeve welds of the LPCI nozzle and other RV nozzles as applicable.

The staff also needed additional information to clarify how the applicant will inspect the thermal sleeves and thermal sleeve extensions. In case inspections are not performed on the thermal sleeve components, leakage analyses are necessary to ensure that the intended functions of the thermal sleeve components are adequately maintained in a consistent manner with the guidance in Section 3.2.4 of BWRVIP-18-A.

By letter dated October 3, 2012, the staff issued RAI B.1.11-6, in which the staff requested the applicant to clarify the following issues so that the BWR Vessel Internals AMP can be evaluated:

a. Clarify why the applicant’s AMR items for the thermal sleeve components in LRA Table 3.1.2-1 do not include the thermal sleeve and thermal sleeve extension of the reactor vessel feedwater nozzle.

b. Describe the “strategies” in BWRVIP-42, Revision 1, to clarify how the implementation of the strategies will manage cracking of the inaccessible thermal sleeve components of the LPCI nozzle and other reactor vessel nozzles as applicable. Include the following in the description, as applicable.

    1. If the program includes leakage analyses to manage cracking of the thermal sleeve components (e.g., for inaccessible locations), describe the results of the leakage analyses to demonstrate that cracking of the thermal sleeve components does not affect the intended functions of these components.

    2. If the program includes inspections to manage cracking of the thermal sleeve components, describe the method and frequency of the inspections to demonstrate the adequacy of the inspections. As part of the response, clarify whether any of the thermal sleeve welds of the recirculation inlet, core spray, RHR/LPCI and feedwater nozzles can be examined using UT that is applied on the outer surface of the associated piping and safe ends.

c. Ensure that the LRA is consistent with the response.

In the October 22, 2012, response to part (a), the licensee explained that the thermal sleeves are not welded to the nozzles so they are not part of the pressure boundary. With this design, the thermal sleeve has no safety functions and its failure would not significantly impact safety-related components within the vessel, the thermal sleeves have no intended functions for license renewal and are not subject to aging management review. As a result, no AMR items are included in the LRA.

For part (b), the applicant’s response states that strategies for managing cracking of the inaccessible thermal sleeve components, which includes both leakage evaluation and inspection, are based on BWRVIP-168, *BWR Vessel and Internals Project, Guidelines for Disposition of Inaccessible Core Spray Piping Welds in BWR Internals,* which is the basis for inspection requirements for inaccessible core spray welds included in BWRVIP-18, Revision 1, *BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines.* NRC review of BWRVIP-18, Revision 1, is complete. None of the thermal sleeve welds of the recirculation inlet, CS, or RHR/LPCI nozzles can be examined using UT that is applied on the outer surface of the associated piping and safe ends. As indicated in part (a) above, the feedwater thermal sleeves are not welded to the nozzles nor are they subject to aging management review.

Finally for part (c), the applicant stated that no changes to the LRA are needed.

The staff has reviewed the October 22, 2012, response and finds that the applicant has provided enough detail for the staff to evaluate the AMP. Because the thermal sleeves are not welded to the feedwater nozzle, the staff agrees that there are no additional items required in LRA Table 3.1.2 1. In addition, the staff noted that the details of the BWRVIP strategies for aging management of inaccessible core spray line welds are part of the staff review for BWRVIP-18 and do not require further consideration for the review of BWRVIP-42. The staff verified that the updated inspection and evaluation guidelines in BWRVIP-18, Revision 1, for core spray lines were approved in a safety evaluation dated January 30, 2012 (ML113620684 and ML120230338). The staff's concerns described in RAI B.1.11-6 are resolved.

Summary. Based on its audit and review of the applicant's responses to RAIs, 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.M11. In addition, the staff reviewed the enhancement associated with the "detection of aging effects" program element and finds that when the applicant submits a plant-specific description of the inspection procedures to be used for susceptible components, and gets approval from the NRC staff, the AMP will adequately manage the applicable aging effects.

Review of License Renewal Action Items – Appendix C. The applicant is also required to comply with the license renewal action items specified in the staff's SEs for the following BWRVIP reports for the extended period of operation.

Several of the BWRVIP documents credited for GGNS license renewal have common action items in the NRC SE reports for license renewal that are not associated with a TLAA. The following paragraphs address the applicant's responses to these common license renewal action items and the corresponding staff's evaluation.

The applicant made the following response to the three license renewal action items which are listed in staff's SEs for the aforementioned BWRVIP reports.

1. GGNS's AMPs for the RVI components are bounded by the BWRVIP reports;
2. The UFSAR supplement addresses a summary of the programs and activities specified in the applicable BWRVIP reports; and
3. GGNS states that no TS changes have been identified as a result of implementing the AMP for the RVI components.

The staff reviewed the applicant's disposition of these three license renewal action items and concludes that the applicant complied with the intent of the license renewal action items that were specified by the staff in its SEs for the aforementioned BWRVIP reports.

The following paragraphs address the applicant's responses to report-specific license renewal action items and the corresponding staff's evaluation.

For Action Item 5 in BWRVIP-25, the applicant is required to follow the inspection recommendation until an expanded technical basis is approved by the staff. The applicant's response to Action Item 5 in BWRVIP-25 states that there are no requirements for BWR/6 plants like GGNS. The staff reviewed the report and found that the BWRVIP does not recommend inspections for the rim hold-down bolts because BWR/6 vessels already have wedges installed. The staff finds the applicant's response acceptable.

For Action Item 5 in BWRVIP-42 Revision 1, the BWRVIP committed in Section 2.2.2 of the original report, dated December 1997, to the development of technology to inspect inaccessible welds in the low-pressure coolant injection nozzle coupling to the reactor vessel and the shroud. Inspection is important because the environment for some inaccessible welds has a relatively high electrochemical potential where stress corrosion cracking can occur, leading to leakage. Bypass of LPCI flow to the annulus has significant safety consequences mainly for a recirculation line break because the diverted LPCI flow to the annulus would be lost through the break. Applicants using this report are required to identify this 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 Action Item 5 in BWRVIP-42-A says that the BWRVIP has developed strategies to ensure the integrity of inaccessible welds that are included in Section 3 of BWRVIP-42, Revision 1. The staff addressed this issue in RAI B.1.11-6b discussed in the enhancement section. In its response dated October 22, 2012, the applicant described the strategies for managing cracking of the inaccessible thermal sleeve components as being the same as those found in BWRVIP-18, Revision 1, which is currently under staff review. Considering the progress that has been made regarding the inspection strategies for inaccessible welds, the staff accepts the RAI response and the staff's concern for Action Item 5 in BWRVIP-42, Revision 1, is resolved.

The license renewal action items specified in the staff's SE dated October 18, 2001, for the BWRVIP-74-A report address the aging effects on the RVI components, and this report provides requirements to effectively manage the aging effects during the period of extended operation. The BWRVIP-74-A report also addresses the license renewal action items associated with TLAAs for the period of extended operation. The following paragraphs address the TLAAs and the AMP related to RVI components that are 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.

Per item 4 of the license renewal action item in the staff's SE for the BWRVIP-74 report, the applicant acknowledges that the vessel flange leak detection (VFLD) line is included in the scope of license renewal. Cracking of the component is managed by the Water Chemistry Program, with the effectiveness verified by the One-Time Inspection Program. The staff accepts the applicant's proposed AMP for the VFLD line because (a) controlling water chemistry will enable the applicant to effectively manage the occurrence of any cracking or loss of material in the VFLD line, and (b) the one-time inspection program will adequately determine if the aging degradation has occurred.

Item 5 of the license renewal action items in the staff's SE for the BWRVIP-74 report requires that the applicant describe how each plant-specific AMP addresses the ten elements listed in GALL Report AMP XI.M9. The applicant stated that Appendix B of the LRA addresses the required 10 elements. The staff reviewed Appendix B and accepts the applicant's response because Appendix B adequately addresses the 10 elements of the GALL Report AMP.

Item 6 of the license renewal action items in the staff's SE for the BWRVIP-74 report requires that the applicant shall include a water chemistry program in its LRA to ensure that it can effectively manage IGSCC in the RCS systems. The applicant in its response stated that it would comply with the BWRVIP-190 report which superseded the BWRVIP-29 report. The staff accepts this response as the applicant's compliance with the requirements of the BWRVIP-190 provides adequate mitigation to the occurrence of IGSCC.

Item 7 of the license renewal action items in the staff's SE for the BWRVIP-74 report requires that the applicant identify its RPV surveillance program. The applicant stated that it has implemented the staff-approved BWRVIP Integrated Surveillance Programs (ISPs) for the period of extended operation. Compliance with the staff-approved ISP enables the applicant to effectively monitor neutron embrittlement of the RPV materials and, therefore, the staff finds the applicant's response acceptable.

Operating Experience. During the staff audit, the applicant provided several inspection reports associated with the previous inspections that were performed on the RVI components. The staff reviewed the inspection reports and concluded that the applicant complied with the inspection requirements of the applicable BWRVIP reports which are consistent with the GALL Report AMP. The staff also reviewed the applicant's implementation of its corrective action methodology for identifying nonconforming conditions and found the applicant's corrective action methodology acceptable.

The "operating experience" program element of GALL Report AMP XI.M9 states that plant-specific and any relevant industry experience is to be summarized. However, during its audit, the staff noted that there would be a new steam dryer installed as part of the EPU and no summary of the industry experience with steam dryers operating under EPU conditions. By letter dated June 27, 2012, the staff issued RAI B.1.11-5 requesting that the applicant provide details of the industry experience with steam dryers operating under EPU conditions and how that has influenced the design and fabrication of the new steam dryer at GGNS.

In the applicant's July 25, 2012, response to RAI B.1.11-5, the applicant stated that the inspection history at the Susquehanna Steam Electric Station (SSES), Units 1 and 2 was considered in the submitted license amendment request (LAR) for the EPU, and resulted in changes implemented for the GGNS replacement steam dryer, including revised fabrication procedures and the elimination of tack welds. Furthermore, in the response to RAI 12 in Attachment 1 to GNRO-2012/00011, Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1, dated February 20, 2012, the April 2011 inspections at SSES, Unit 2 resulted in corrective actions to the GGNS dryer manufacturing process.

The staff has reviewed the response and considers that the details demonstrate that relevant industry experience was used by the applicant in the new steam dryer for GGNS. This resolves the issue related to RAI B.1.11-5.

The staff, therefore, concludes that the applicant adequately implemented the inspection criteria of the BWRVIP reports for the RVI components and that the AMP is consistent with GALL Report AMP XI.M9. Based on the review of the operating experience for GGNS, the staff concludes that by implementing AMP B.1.11, the applicant adequately demonstrated its capability in identifying the aging effects associated with the RVI components. The applicant also demonstrated that it will adequately monitor the aging degradation of the RVI components by using proper corrective actions to restore the structural integrity of the RVI components.

Based on its audit and review of the application, and review of the applicant's responses to RAIs, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. The applicant provided its UFSAR supplement summary for its BWR Vessel Internals Program in LRA Section A.1.11. The staff confirms that the UFSAR supplement summary description for the BWR Vessel Internals Program conforms to the staff's recommended UFSAR supplement described in SRP-LR Table 3.0-1. The staff finds that UFSAR Supplement Section A.1.11 provides an acceptable UFSAR supplement summary description of the applicant's BWR Vessel Internals Program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's BWR Vessel Internals, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are 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).

3.0.3.1.11 Compressed Air Monitoring

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.12 describes the existing Compressed Air Monitoring Program as consistent, with enhancements, with GALL Report AMP XI.M24, "Compressed Air Monitoring." The Compressed Air Monitoring Program manages loss of material in compressed air systems by monitoring air samples for moisture and contaminants and by inspecting internal surfaces within compressed air systems. The inspection frequency and acceptance criteria are based on the applicant's response to NRC GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," issued August 1988, and industry standards and guidance documents.

<u>Staff Evaluation</u>. 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.M24. For the "detection of aging effects" and "monitoring and trending" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M24 recommends that the program include periodic visual inspections of critical component internal surfaces (compressors, dryers, after-coolers, and filters) to detect signs of loss of material due to corrosion. Enhancement 2 to the LRA AMP identifies an enhancement to the "parameters monitored or inspected," and "monitoring and trending" program elements, which states that the program will be enhanced to include periodic and opportunistic inspections of accessible internal surfaces of piping and components in certain compressed air systems. However, the staff determined that the LRA AMP "detection of aging effects" program element should also be included in the enhancement. Additionally, it was not clear if the critical components (i.e., compressors, dryers, after-coolers, and filters) will be included in the periodic and opportunistic inspections, nor was it clear what specific types and frequency of inspections will be used. By letter dated April 11, 2012, the staff issued RAI B.1.12-1 requesting that the applicant clarify whether Enhancement 2 to the LRA AMP applies to the "detection of aging effects" program element and to clarify the types of components to be inspected and the specific inspection type and frequency that will be used.

In its response dated May 9, 2012, the applicant stated that LRA Sections A.1.12 and B.1.12 will be revised to include the "detection of aging effects" element as part of Enhancement 2 to the Compressed Air Monitoring Program. The applicant also stated that the internal surfaces of compressors, dryers, after-coolers, and filters will be inspected to detect signs of loss of material, and that the guidance in ASME Code O/M-S/G-1998, Part 17, will be used for inspection frequency and inspection methods for these components.

The staff reviewed the applicant's response and changes to LRA Sections A.1.12 and B.1.12 and finds the applicant's response acceptable because the applicant has extended the enhancement to include the "detection of aging effects" program element. Additionally, the applicant clarified that the internal surfaces of the critical components will be inspected following the guidance in ASME O/M-S/G-1998, Part 17, which is consistent with the GALL Report. The staff's concern described in RAI B.1.12-1 is resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," 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.

Enhancement 1. LRA Section B.1.12 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that the Compressed Air Monitoring Program will be enhanced to apply a consideration of the guidance of ASME OM-S/G-1998, Part 17; American National Standards Institute (ANSI)/ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147 for air system contaminant limits. 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 air contaminant limits will be informed by the cited standards, which is consistent with the GALL Report.

Enhancement 2. LRA Section B.1.12 states an enhancement to the "parameters monitored or inspected" and "monitoring and trending" program elements. In this enhancement, the applicant stated that the Compressed Air Monitoring Program will be enhanced to include periodic and opportunistic inspections of accessible internal surfaces of piping and components in certain compressed air systems. The "monitoring and trending" program element in GALL Report AMP XI.M24 recommends that the program include system dew point recording and trending, air quality analysis results review and trending, and trending of visual inspection results to ascertain if adverse long-term trends exist. Additionally, the program recommends that test data be analyzed and compared to data from previous tests to provide for the timely detection of aging effects on passive components. However, the enhancement does not describe any dew point recordings, air quality checks, or trending practices recommended for this program. By letter dated April 11, 2012, the staff issued RAI B.1.12-2 requesting that the applicant describe the monitoring and trending practices for the Compressed Air Monitoring Program and to clarify how the enhancement to the LRA AMP applies to the "monitoring and trending" program element.

In its response dated May 9, 2012, the applicant stated that its implementing procedures include daily readings of system dew point. The applicant also stated that air quality analysis results are reviewed to determine if alert levels or limits have been reached or exceeded, and that this review also checks for unusual trends. The applicant clarified that the enhancement applies only to the GALL Report statement that "[v]isual inspection results are compared to previous results to ascertain if adverse long-term trends exist."

The staff finds the applicant's response acceptable because the applicant's procedures include daily dew point readings, which is consistent with the guidance in the GALL Report AMP. The applicant also performs reviews of air quality analysis results, as well as reviews for unusual trends, which is consistent with the GALL Report AMP. The staff's concern described in RAI B.1.12-2 is resolved.

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 it will make the program consistent with the recommendations in the GALL Report AMP.

Summary. Based on its audit, and review of the applicant's responses to RAIs B.1.12-1 and B.1.12-2 of the applicant's Compressed Air Monitoring Program, the staff finds that program elements one through six 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 enhancements, and response to RAI B.1.12-2, associated with the "preventive actions," "parameters monitored or inspected," 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.1.12 summarizes operating experience related to the Compressed Air Monitoring Program. In 2003, the applicant found evidence of rust during internal inspection of the standby diesel generator starting air tanks. Actions were taken to remove the rust.

In 2009, the applicant identified a concern regarding high dew points for the Division 1, 2, and 3 diesel generator starting air systems for the previous 2 years. Corrective actions included creating new repetitive tasks for maintenance on the air dryers and revising the procedure for desiccant replacement. The response to a high dew point reading now requires a check of the dryer tower crossover valves and a satisfactory dryer retest after replacement of the desiccant.

In 2010, the applicant collected instrument air samples that exceeded the procedural limit for particulate size. The cause was attributed to filters on temporary air compressors used during refueling outage 17. A system modification was implemented to remove the temporary air compressors from the system.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.12 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 include a summary description of the program nor does it reference the applicant's crediting of its response to GL 88-14. 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 April 11, 2012, the staff issued RAI B.1.12-3 requesting that the applicant provide further information on the summary description of the program and crediting of its response to GL 88-14.

In its response dated May 9, 2012, the applicant stated that it inadvertently omitted the following statement from the original LRA submission:

> The Compressed Air Monitoring Program manages loss of material in compressed air systems by monitoring air samples for moisture and contaminants and by inspecting internal surfaces within compressed air systems. Inspection frequency and acceptance criteria are based on the GGNS response to NRC Generic Letter 88-14 and applicable industry standards and guidance documents.

In its response, the applicant provided a revision to LRA Section A.1.12, which now includes the above paragraph.

The staff finds the applicant's response acceptable because the inclusion of the above information provides an adequate description of the program. 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.1.12-3 is resolved.

The staff also noted that the applicant committed (Commitment No. 7) to enhance the Compressed Air Monitoring Program to apply a consideration of industry guidance and to include periodic and opportunistic inspections of accessible internal surfaces of certain compressed air systems entering the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended by letter dated May 9, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Compressed Air 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 through Commitment No. 7 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the

UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.12 Containment Inservice Inspection – IWE Program

Summary of Technical Information in the Application. LRA Section B.1.13 describes the existing Containment Inservice Inspection – IWE Program as consistent with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE." The LRA also states that the program performs a general visual examination to assess the condition of the containment steel liner and to detect evidence of degradation that may affect structural integrity or leak tightness. This examination satisfies the requirements of the ASME Code (to include the 1998 edition with 1999 and 2000 addenda, 2001 edition with 2003 addenda, and the 2004 Code Edition) Section XI, Subsection IWE Examination Category E-A. The LRA further states that the program is augmented by existing plant procedures to ensure that the selection of bolting material, installation torque or tension, and the use of lubricants and sealants is appropriate for the intended purpose. These procedures reference guidance contained in EPRI TR-104213, NUREG-1339, and EPRI NP-5769 to ensure proper specification of bolting material, lubricant, and installation torque.

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.S1. For the "scope of program," "preventive actions," "parameters monitored or inspected" and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs.

The "acceptance criteria" program element in GALL Report AMP XI.S1 recommends that material loss exceeding 10 percent of the nominal containment wall thickness, or material loss that is projected to exceed 10 percent of the nominal wall thickness, before the next examination that is accepted by engineering evaluation, is to be reexamined during the next inspection period in accordance with IWE-3122 and IWE-2420(b). However, during its audit, the staff found that the applicant's Containment Inservice Inspection – IWE Program identified flaws or degradation that exceeded 10 percent of the nominal wall thickness of the suppression pool liner plate during an inspection in 2007 that were accepted by engineering evaluation, and were not scheduled to be reexamined during the next inspection period. By letter dated May 9, 2012, the staff issued RAI B.1.13-1 requesting the applicant describe the basis for accepting pits greater than 10 percent of the liner thickness and for not performing augmented inspection.

In its response dated June 6, 2012, the applicant stated that the GGNS suppression pool liner plate, which is backed by concrete, is not a part of the containment pressure boundary and was not designed in accordance with ASME Code Section III, Division I. This area of the suppression pool is inspected under the Structures Monitoring Program, using a procedure that is also used for the Containment Inservice Inspection – IWE Program. The applicant further stated that it has evaluated the identified pits as documented in the GGNS corrective action process and site calculations. The evaluation states that the reduction in liner plate thickness is acceptable. The calculation concluded that with a liner plate thickness of 0.225 inch, a factor of safety of 3.17, based on ultimate stress, and a factor of safety of 10.54 based on yield stress, was maintained. The thinnest wall thickness identified was 0.231 inch, which is bounded by this evaluation.

The staff reviewed the applicant's response to RAI B.1.13-1 and found it lacked specific information concerning consistency between the AMP and GALL Report AMP XI.S1 and IWE-1100. Both GALL Report AMP XI.S1 and IWE specifically include metallic shell liner of concrete containment pressure-retaining components and their integral attachments within the scope of the IWE inspection program. The applicant's IWE inspection report of April 2007 for the suppression pool liner plate identified loss of thickness at more than 100 locations in the base slab and walls of the concrete containment portion of the suppression pool liner plate. The loss of thickness was up to 7.6 percent. Therefore, an augmented examination is required to be performed during the next inspection period in accordance with ASME Code Subsection IWE requirements even though the applicant has performed an evaluation that loss of thickness of up to 10 percent of the liner plate nominal thickness is acceptable. The staff issued RAI B.1.13-1a requesting the applicant to provide justification for inspecting the base slab and wall liner plate of the suppression pool, which is an integral part of the concrete containment, in accordance with the Structures Monitoring Program AMP. In addition, the RAI requested the applicant to provide a justification for not performing the augmented inspection of the flaws as required by IWE-2420 and Table IWE-2500-1, Examination Category E-C.

In its response to RAI B.1.13-1a, dated August 21, 2012, the applicant stated that the containment floor and cylinder wall portion of the suppression pool and the intersecting portion at the containment floor liner are inspected in accordance with the Containment Inservice Inspection – IWE Program. The applicant also stated that the April 2007 IWE inspection report for the suppression pool liner plate identified loss of thickness in one location, which was on the flat circular foundation base slab liner plate and multiple locations on the weir wall liner located within the drywell. The flaw located on the flat circular foundation base slab liner plate is within the containment pressure boundary, is subject to the requirements of ASME Code Section XI, Subsection IWE and is scheduled for inspection during the next inspection interval as required by IWE-2420 and Table IWE-2500-1, Examination Category E-C. The applicant also stated that the pitting on the weir wall liner is not part of the containment pressure boundary portion of the suppression pool liner plate. The pitting was determined to be punch marks made to the liner plate during its construction and was not a result of age-related degradation, structural deformation or displacement of the liner plate.

The staff reviewed the applicant's response and found it acceptable because the applicant inspects the stainless steel liner in the suppression pool that is part of the concrete containment pressure retaining boundary in accordance with the Containment Inservice Inspection – IWE Program. The applicant has performed an engineering evaluation in accordance with IWE-3122.3 and determined that loss of metal thickness of up to 10 percent is acceptable. In addition, the applicant plans to perform augmented inspection of the one flaw in the suppression pool base slab that is located within the containment pressure retaining boundary in accordance with ASME Code Section XI, Subsection IWE, Examination Category E-C requirements. The staff also finds it acceptable that the applicant inspects the suppression pool liner plate that is not a part of the containment boundary, including the weir wall, in accordance with the Structures Monitoring Program. Furthermore, the staff agrees that the pitting in the weir wall is due to punch marks made to the liner during construction and are not due to age-related degradation, and that there is no need to perform additional evaluation or reexamination during the next inspection period. The staff's concerns described in RAI B.1.13-1 and RAI B.1.13-1a are resolved.

GALL Report AMP XI.S1 states that 10 CFR 50.55a imposes the ISI requirements of the ASME Section XI, Subsection IWE for steel containments (Class MC [metal containment]) and steel liners for concrete containments [Class CC]). In accordance with 10 CFR 50.55a(b)(2)(ix)(B), visual examinations required by Subsection IWE shall be performed with the maximum direct examination distance specified in Table IWA-2210-1. However, Section 3.2 of the GGNS License Renewal Project, Aging Management Program Evaluation Report Civil/Structural for Containment Inservice Inspection – IWE, states that the requirements of IWA-2210 are not applicable to Subsection IWE visual examinations per IWE-2100. By letter dated May 9, 2012, the staff issued RAI B.1.13-2 requesting the applicant to describe the basis for not using the requirements of IWA Table 2210-1 as amended by 10 CFR 50.55(a).

In its response dated June 6, 2012, the applicant stated that Section 3.2 of the GGNS AMP evaluation report for the Containment Inservice Inspection – IWE Program was intended to indicate that the GGNS Containment Inservice Inspection – IWE Program uses IWA Table 2210-1 as amended by 10 CFR 50.55a(b)(2)(ix)(B), as required by 10 CFR 50.55(a). The applicant also reiterated that Containment Inservice Inspection – IWE Program is consistent with the program described in the GALL Report AMP XI.S1, ASME Section XI, Subsection IWE, with no exceptions. The staff finds the applicant's response acceptable because the applicant's program uses IWA Table 2210-1 as amended by 10 CFR 50.55a(b)(2)(ix)(B). The applicant's AMP is consistent with GALL Report AMP XI.S1. The staff's concern described in RAI B.1.13-2 is resolved.

The "preventive actions" program element in GALL Report AMP XI.S1 recommends that the selection of bolting material installation torque or tension and the use of lubricants and sealants should be in accordance with the guidelines of EPRI NP-5769, EPRI TR-1 04213, and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of structural bolting. However, during the audit, the staff noted that Section 3.2 of the GGNS License Renewal Project, Aging Management Program Evaluation Report Civil/Structural for Containment Inservice Inspection – IWE, states that molybdenum disulfide lubricant was previously used in the torquing process during construction and maintenance activities. The staff is concerned that AMP or the associated evaluation report did not identify any plan for inspecting high-strength bolts that were previously torqued using molybdenum disulfide lubricant.

By letter dated May 9, 2012, the staff issued RAI B.1.13-3 requesting the applicant to describe the plan, including sample size and frequency, for inspecting high-strength bolts that were previously torqued using molybdenum disulfide lubricant. The staff noted that the plan should also describe the schedule for inspection to establish a trend for aging management of these high-strength bolts during the period of extended operation.

In its response dated June 6, 2012, the applicant stated that it assumed that molybdenum disulfide may have been used as a lubricant in the torquing process during construction with high-strength structural bolting material (i.e., American Society for Testing and Materials [ASTM] A325 and A490). However, this bolting is not part of the containment liner construction and no Class MC component supports are integrally attached to the liner. However, as stated in Section 4.1 of the GGNS License Renewal Project, Aging Management Program Evaluation Report Non-Class I Mechanical, procedures will be enhanced to prohibit use of this lubricant, even though there is no ASTM A325 and A490 Class MC pressure-retaining component bolting integral to the GGNS containment liner plate. This enhancement is described in the LRA Section B.1.3, Bolting Integrity, since the application and use of lubricants are governed by site procedures that are the implementing procedures for the Bolting Integrity Program.

The staff finds the applicant's response acceptable because high-strength bolting material conforming to ASTM A325 and A490 has not been used during original containment liner construction, and no Class MC component supports are integrally attached to the liner. In addition, the applicant plans to enhance procedures to prohibit use of molybdenum disulfide lubricant. The staff's concern described in RAI B.1.13-3 is resolved.

The "parameters monitored or inspected" program element in GALL Report AMP XI.S1 recommends that pressure-retaining surfaces of the containment be inspected for evidence of corrosion, cracking, and wear. However, during the audit, the staff reviewed the document Program Section No. CEP-CISI-102, "Program Section for ASME Code Section XI, Division 1, GGNS Containment Inservice Inspection Program." Appendix A of this document lists CISI drawings for IWE Inspections. The drywell and weir wall liner plates between elevations 93 feet and 117 feet that are located in the suppression pool and the steel drywell head were not listed in Appendix A. Therefore, by letter dated May 9, 2012, the staff issued RAI B.2.1.13-4 requesting the applicant to provide justification for not inspecting the drywell and weir wall liner plates between elevations 93 feet and 117 feet that are located in the suppression pool and the steel drywell head.

In its response dated June 6, 2012, the applicant stated that drywell, drywell head, the suppression pool (above containment floor and not part of containment cylinder wall) and weir wall liner plates, including the area between elevations 93 feet and 117 feet located in the suppression pool, are not Class MC pressure-retaining components of the containment. The applicant revised LRA Table 3.5.2-1 consistent with the response. The applicant also stated in response to RAI B.1.13-1 that the suppression pool is inspected under the Structures Monitoring Program using a procedure that is also used for the Containment Inservice Inspection – IWE Program.

The staff's conclusion is based on a review of the description of the containment liner plate, weir wall, and suppression pool liner plate in Section 3.8 of the UFSAR. However, it is not clear how the drywell, drywell head, weir wall, and suppression pool can be inspected under the Structures Monitoring Program using the Containment Inservice Inspection – IWE procedure since "detection of aging effects" and "acceptance criteria" elements of the two programs are significantly different. In addition, the "scope of program" element of LRA B.1.42 does not include drywell, drywell head, weir wall, and suppression pool liner plates. Therefore, the staff issued RAI B.1.13-4a requesting the applicant to explain the basis for using the inspection procedures of Containment Inservice Inspection – IWE Program for inspecting components that are included in the scope of the Structures Monitoring Program. In addition, the applicant was asked to explain why the drywell, drywell head, weir wall, and suppression pool liner plates are not included in Enhancement 1 of the Structures Monitoring Program.

In its response to RAI B.1.13-4a, dated August 21, 2012, the applicant stated that the drywell, drywell head, weir wall, and suppression pool liner plates are included in the GGNS SMP procedure but they are not specifically listed as separate components. For clarification, the applicant revised LRA Sections A.1.42 and B.1.42 to explicitly identify the following additional structural components/commodities: drywell electrical penetration sleeves, drywell equipment hatch, drywell head, drywell head access manway, drywell liner plate, drywell mechanical penetration sleeves, drywell personnel access lock, and weir wall liner plate. The staff finds the applicant's response acceptable because the applicant has revised the UFSAR supplement and AMP to identify that all drywell and suppression pool components that are not part of the containment pressure boundary that will be managed for aging in accordance with Structures Monitoring Program. The staff's concerns described in RAI B.1.13-4 and RAI B.1.13-4a are resolved.

The program description section of GALL Report AMP XI.S1 recommends the Containment Inservice Inspection – IWE Program to be implemented in accordance with the ASME Code, 2004 edition, as approved in 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), ISI of components and system pressure tests conducted during successive 120-month inspection intervals must comply with the requirements of the latest edition and addenda of the Code referenced in the 10 CFR 50.55a(b), 12 months before the start of the 120-month inspection interval. However, during the audit, it was not clear to the staff that the Containment Inservice Inspection – IWE Program is consistent with GALL Report AMP XI.S1 because Section 3.2 of the GGNS License Renewal Project, Aging Management Program Evaluation Report Civil/Structural for the Containment Inservice Inspection – IWE states that IWE examination satisfies the requirements of the ASME Code Edition 1998 edition with 1999 and 2000 addenda, 2001 edition with 2003 addenda, and the 2004 edition. By letter dated May 9, 2012, the staff issued RAI B.1.13-5 requesting the applicant to identify the ASME Code edition that is being used during the current inspection interval, and if this ASME Code edition is consistent with GALL Report recommendations and 10 CFR 50.55a(g)(4) requirements.

In its response dated June 6, 2012, the applicant stated that the third inspection interval for GGNS began in 2008. Consistent with 10 CFR 50.55a, the ASME Section XI Code of record for GGNS Containment Inservice Inspection – IWE Program for the third inspection interval is the 2001 Edition with the 2003 Addenda.

The 10 CFR 50.55a was amended on October 1, 2004, to incorporate by reference the 2001 Edition of ASME Section X Code, up to and including the 2003 Addenda. The 2004 Edition of Section XI, Division 1, of the ASME Code was not endorsed by 10 CFR 50.55a until September 10, 2008. Therefore, the staff finds the applicant's response acceptable because it is conducting the containment liner plate examination in accordance with the 2001 edition with 2003 addenda of the ASME Code, and as specified in 10 CFR 50.55a to use of the latest edition and addenda of the Code referenced in 10 CFR 50.55a(b), 12 months before the start of the 120-month inspection interval. The staff's concern described in RAI B.2.13-5 is resolved.

Based on its audit, and review of the applicant's response to RAIs B.1.13-1, B.1.13-1a, B.1.13-2, B.1.13-3, B.1.13-4, B.1.13-4a, and B.1.13-5, 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.

Operating Experience. LRA Section B.1.13 summarizes operating experience related to the Containment Inservice Inspection – IWE Program. The applicant performed a general visual inspection of the containment liner plate in 2003 and identified a gouge. An engineering review concluded that the liner plate was still capable of performing its intended function to provide a leak-tight barrier after a design basis accident (DBA). The gouge was repaired in 2004. Visual examination of the containment liner in 2007 revealed flaking, blistering, peeling, and chipping conditions that were acceptable as is. Identification of degradation before loss of intended function provides evidence that the program is effective for managing aging effects. 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.13 provides the UFSAR supplement for the Containment Inservice Inspection – IWE 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 applicant's Containment Inservice Inspection – IWE 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.S1. 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 Containment Inservice Inspection – IWL

Summary of Technical Information in the Application. LRA Section B.1.14 describes the existing Containment Inservice Inspection – IWL Program as consistent with GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL." The LRA states that the Containment Inservice Inspection – IWL Program is an existing program that performs general visual examination to assess the overall condition of the containment concrete and to detect evidence of degradation that may affect structural integrity or leak tightness. These examinations meet the requirements of the ASME Code (to include 1998 Edition with 2000 Addenda, 2001 Edition through the 2003 Addenda, and 2004 Edition) Section IWL Examination Category L-A.

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.S1. For the "parameters monitored or inspected" and "acceptance criteria" 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 GALL Report AMP XI.S2, recommends that the containment concrete surfaces be examined for evidence of damage or degradation, such as those defined in American Concrete Institute (ACI) 201.1R, "Guide for Making a Condition Survey of Concrete in Service," and ACI 349.3R. However, during the audit, the staff found that the applicant's Aging Management Program Evaluation Report for Civil/Structural for Containment Inservice Inspection – IWL, only identifies ACI 349.3R criteria for the concrete containment surface examination. ACI 201.1R was not referenced for conducting containment concrete surface visual examination. By letter dated June 27, 2012, the staff issued RAI B.1.14-1 requesting that the applicant describe the methods that will be used for conducting containment concrete visual surface examination. In addition, the applicant was asked to describe if these methods are consistent with the guidance provided in ACI 201.1R.

In its response dated July 25, 2012, the applicant stated that GGNS Containment Inservice Inspection – IWL Program is consistent with the parameters monitored and inspected as outlined in ASME Code Section XI IWL-2500. GGNS performs a general visual examination either directly or remotely with sufficient illumination (natural or artificial) and resolution (suitable for the local environmental conditions) to assess the general condition of the accessible containment concrete surfaces from permanent vantage points. The objective of this examination is to detect evidence of degradation or distress of the concrete surfaces being examined that could affect the structural integrity of the containment. Remote techniques, when used, are demonstrated to detect a 1/32-inch black line on a neutral gray card. Alternatively, the responsible engineer may approve the use of other remote examination techniques subject to the provisions of 10 CFR 50.55a. Examiners shall visually examine the surface areas to be inspected and document the results of the inspection on appropriate forms identified in the procedure. ACI 201.1R states that personnel conducting the condition survey must select those items important to the specific concerns relating to the reasons for the survey. The conduct of these inspections is in accordance with ASME Section XI IWL and the guidance of ACI 349.3R "Evaluation of Existing Nuclear Safety-Related Concrete Structures." ACI 201.1 R is used as input to the Containment Inservice Inspection – IWL Program for establishing appropriate parameters to be monitored and inspected. Therefore, the inspection methods are consistent with the guidance in ACI 201.1 R.

The staff finds the applicant's response acceptable because the applicant confirmed that ACI 201.1 R is used as input to the Containment Inservice Inspection – IWL Program for establishing appropriate parameters to be monitored and inspected. The staff's concern described in RAI B1.14-1 is resolved.

The "acceptance criteria" program element of GALL Report AMP XI.S2 recommends that quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R-02 may be used to augment the qualitative assessment of the Responsible Engineer. The applicant's Containment Inservice Inspection Program Plan provides the examination process of IWL Program in Appendix B, "Containment Inservice Inspection Examination Process Flowchart," and Appendix C, "GGNS Recording and Screening Criteria," in the applicant's procedure of CEP-CII-004, Revision 302, "General and Detailed Visual Examinations of Concrete Containments." However, the staff could not determine whether the quantitative acceptance criterion for containment concrete surface visual examination is considered in the applicant's program. By letter dated June 27, 2012, the staff issued RAI B.1.14-2 requesting that the applicant describe the acceptance criteria used for the containment concrete surface visual examination and describe if the acceptance criteria are consistent with the quantitative acceptance criteria recommended in Chapter 5 of the ACI 349.3R-02.

In its response dated July 25, 2012, the applicant stated:

> The GGNS acceptance criteria used for the containment concrete surface visual examination state, if any of the conditions listed below are present, the condition must be recorded on the examination form and the form forwarded to the appropriate personnel for acceptance review.
>
> 1. active leaching or chemical attack to include areas of exudation, efflorescence, stalactites or stalagmites
> 2. active abrasion or erosion degradation
> 3. popouts or voids 50 mm (2 inches) or more in diameter (or of equivalent surface area)
> 4. scaling 30 mm (1 - 1/8 inches) or more in depth
> 5. spalling 20 mm (3/4 inch) or more in depth
> 6. spalling 200 mm (8 inches) or more in any dimension

7. excessive corrosion of embedded metallic surfaces
8. corrosion staining from corrosion of reinforcing steel or from an unknown source on the concrete surface
9. cracks 1 mm (0.04 inch) in maximum width, measured below any surface enhanced widening
10. excessive deflection, settlement or other physical movement
11. conditions that indicate the presence of or cause degradation of inaccessible concrete

In addition, the indications listed above are considered active unless the indications have been previously reported and remain essentially unchanged, or the evaluated indications have been determined inactive. These acceptance criteria are consistent with the quantitative acceptance criteria recommended in Chapter 5 of ACI 349.3R-02.

The staff reviewed the applicant's response to RAI B1.14-2 and noted that the detailed acceptance criteria described for the containment concrete surface is based on the quantitative limits of the second tier acceptance criteria in Subchapter 5.2.1 of ACI 349.3R-02. This did not appear to be consistent with the guidelines recommended in Chapter 5 of ACI 349.3R-02, which require further evaluation if concrete surface conditions did not meet the quantitative limits of first tier acceptance criteria in Subchapter 5.1.1. The applicant did not provide any justification for excluding the first tier evaluation criteria of ACI 349.3R-02 for the containment concrete surface examination. Therefore, by letter dated August 15, 2012, the staff issued follow-up RAI B1.14-2a requesting the applicant to explain the reason for not using the first tier evaluation criteria as defined in Subchapter 5.1 of the ACI 349.3R-02 for the GGNS containment concrete surface examination.

In its response dated September 13, 2012, the applicant stated that GGNS Containment Inservice Inspection – IWL containment concrete surface examination recording criteria are consistent with first tier criteria as defined in Subchapter 5.1 of ACI 349.3R-02 and include the following:

1. appearance of leaching or chemical attack to include areas of exudation, efflorescence, stalactites or stalagmites
2. abrasion or erosion degradation
3. popouts or voids 20 mm (3/4 inch) or more in diameter (or of equivalent surface area)
4. scaling 5 mm (3/16 inch) or more in depth
5. spalling 10 mm (3/8 inch) or more in depth
6. spalling 100 mm (4 ~ inches) or more in any dimension
7. excessive corrosion of embedded metallic surfaces
8. corrosion staining on the concrete surface
9. cracks 0.4 mm (0.015 inch) in maximum width, measured below any surface enhanced widening
10. excessive deflection, settlement or other physical movement

The applicant further stated that the concrete surfaces that exceed the above criteria are identified for further evaluation under second tier criteria as defined in ACI 349.3R-02.

The staff finds the applicant's response acceptable because the applicant confirmed that ACI 349.3R-02 evaluation criteria are used to inspect and evaluate the condition of GGNS containment concrete surface. The staff's concern described in RAI B1.14-2a is resolved.

Based on its audit and review of the applicant's responses to RAIs B.1.14-1, B.1.14-2, and B.1.14-2a of the applicant's Containment Inservice Inspection – IWL, 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.S2.

Operating Experience. LRA Section B.1.14 summarizes operating experience related to the Containment Inservice Inspection – IWL. The applicant performed inspections of concrete consistent with the schedule outlined in the ISI program. The reports for 2004 through 2009 showed no adverse indications from these inspections. The applicant provided the process for review of future plant-specific and industry operating experience for this program in LRA Section B.0.4, "Operating Experience." The applicant also stated that the evaluations completed under the operating experience program and corrective action program (CAP) ensure that AMPs continue to be effective in managing the aging effects of in-scope SCs.

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 AMP 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" program element of the GALL Report, AMP XI.S2 states that the implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the period of extended operation. However, during the walkdown of the containment structure on January 31, 2012, the staff noted embedded steel plates in the concrete containment's exterior surface. These embedded steel plates had signs of corrosion and the concrete surface adjacent to these embedded plates had rust stains. It was not clear to the staff if those embedded steel plates are considered in the Containment Inservice Inspection – IWL Program or how the aging of the embedded steel plates will be managed. By letter dated June 27, 2012, the staff issued RAI B.1.14-3 requesting that the applicant describe how the aging of the embedded steel plates located on the exterior surface of the concrete containment will be managed.

In its response dated July 25, 2012, the applicant stated that the aging effect of the embedded steel plates located on the exterior surface of the concrete containment will be managed under the Containment Inservice Inspection – IWL Program in accordance with ASME Code Section XI IWL-1100. The containment dome surface area was evaluated during the last inspection interval and the inspection results indicated that the corrosion on the embedded plates did not exceed the screening criteria and would not jeopardize the structural integrity or leak tightness of the containment. The conditions were found acceptable without the need for an engineering evaluation or other corrective action. These embeds are included as part of item "Containment cylinder wall and dome" in LRA Table 3.5.2-1.

The staff finds the applicant's response acceptable because the embedded steel plates located on the exterior surface of the concrete containment will be managed under the Containment Inservice Inspection – IWL Program in accordance with ASME Code Section XI IWL-1100, and the containment dome surface area was evaluated during the last inspection interval and the inspection results indicated that the corrosion on the embedded plates did not exceed the screening criteria and would not jeopardize the structural integrity or leak tightness of the containment. The staff's concern described in RAI B1.14-3 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.1.14-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.14 provides the UFSAR supplement for the Containment Inservice Inspection – IWL 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 applicant's the Containment Inservice Inspection – IWL 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.S2. 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 Containment Leak Rate

Summary of Technical Information in the Application. LRA Section B.1.15 describes the existing Containment Leak Rate Program as consistent with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J." The LRA states that the program provides for detection of loss of material, cracking, and loss of function in various systems penetrating containment. The LRA states that the program also provides for detection of age-related degradation in material properties of gaskets, O-rings, and packing materials for the primary containment pressure boundary access points. Containment leakage rate tests (LRTs) are performed to assure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the plant TS. The LRA further states that an integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B. Performance of the ILRT per 10 CFR Part 50, Appendix J, demonstrates the leak-tightness and structural integrity of the containment. Local leak rate tests (LLRT) are performed on isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR Part 50, Appendix J, Option B.

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.S4. For the "scope of program" and "monitoring and trending" 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 recommends including all containment pressure boundary components. However, the staff noted that the applicant's TS for 10 CFR Part 50, Appendix J, testing, administered through the Containment Leak Rate program, indicate that the leakage rate program is implemented with approved exemptions. By letter dated August 15, 2012, the staff issued RAI B.1.15-1 requesting the applicant to identify all excluded/exempted components (valves, penetrations, and other components) from the 10 CFR Part 50, Appendix J, testing and state for these components how it plans to manage their aging effects, or justify why an AMP is not necessary.

In its response dated September 13, 2012, the applicant listed components that have been exempted from 10 CFR Part 50, Appendix J, Type C testing but are classified as containment isolation valves per General Design Criterion 55 (i.e., RCPB penetrating containment) or 56 (i.e., primary containment isolation). The applicant explained that the listed valves, although exempted from the requirements for Appendix J, Type C tests, will be managed by several AMPs during the period of extended operation. The applicant will manage the aging effects of the exempted/excluded valves through the following selected AMPs:

- External Surfaces Monitoring program, reviewed in SER Section 3.0.3.1.17 and selected to manage the effects of aging on external surfaces of the components
- Water Chemistry Control - BWR program, reviewed in SER Section 3.0.3.1.41 and selected to manage the effects of aging on internal surfaces of the components
- Compressed Air Monitoring program, reviewed in SER Section 3.0.3.1.11 and selected to manage the effects of aging on internal surfaces exposed to condensation
- Water Chemistry Control - Closed Treated Water Systems program, reviewed in SER Section 3.0.3.1.42 and selected to manage the effects of aging on internal surfaces
- Internal Surfaces In Miscellaneous Piping and Ducting Components program, reviewed in SER Section 3.0.3.1.25 and selected to manage the effects of aging on internal surfaces
- Service Water Integrity program, reviewed in SER Section 3.0.3.1.39 and selected to manage the effects of aging on internal surfaces

In addition, the applicant stated that some of the exempted/excluded components do not require management of aging effects because of their environment, method of construction, or materials used, such as:

- External/Internal surfaces of stainless steel components are exposed to indoor air (e.g., ILRT Drywell and Containment instrument inboard – outboard valves, associated with penetration 110).
- External surfaces of carbon steel components are exposed to temperatures greater than 212°F.

The staff reviewed the applicant's response and found it acceptable because it is consistent with the information in Tables 6.2-44 and 6.2-49 of the UFSAR for Type C testing for containment isolation valves. The staff was concerned that the applicant did not provide any information in its response about the Type B tests required to measure leakage across each pressure-containing or leakage-limiting boundary of primary containment penetrations. The staff discussed this concern in a conference call with the applicant on November 20, 2012. During this conference call, the applicant stated that it would provide a supplemental response to RAI B.1.15-1 which lists the penetrations exempted from Type B tests and how aging management would be accomplished during the period of extended operation. By letter dated December 18, 2012, the applicant supplemented its response. The applicant identified the components that have been exempted from Type B testing and identified the AMPs that would provide aging management for the components during the period of extended operation. The staff reviewed the applicant's supplemental response and found it acceptable based on the following:

a. The inspection ports integral to the guard pipes in containment penetrations are exempted from Type B tests because, as documented in UFSAR Section 3.6A.2.4.3, a weld located between the inner cover and the guard pipe provide part of the containment boundary.
b. The blind flanges in the personnel airlocks are exempted from Type B tests because they are an integral part of the personnel airlocks and are tested during the overall personnel airlock local leak rate test.
c. The double O-ring seals in the process lines associated with containment penetrations 23, 24, 27, 32, and 67 are exempted from Type B tests. UFSAR Table 6.2-49, Note 19, states that these O-rings are associated with restriction orifices and are not required to be Type B tested because the penetration is water sealed.
d. For the exempted components, the applicant identified additional AMPs that will provide aging management of the components during the period of extended operation.

The staff's concern described in RAI B.1.15-1 is resolved, because the applicant provided a list of the components exempted from Type B and C testing, the justification for the exemptions, and an explanation of how aging management for the exempted components will be accomplished during the period of extended operation. Furthermore, the applicant inspects the external surfaces of all containment penetrations in accordance with AMP B.1.13, "Containment Inservice Inspection – IWE."

The "monitoring or trending" program element recommends monitoring of the entire pressure boundary over time based on the option followed. The applicant in its LRA and its basis document indicated that the Containment Leak Rate program follows Option B for the 10 CFR Part 50, Appendix J, testing and that the program is consistent with GALL Report AMP XI.S4. GALL Report AMP XI.S4 "monitoring and trending" program element states:

> Because the LRT program is repeated throughout the operating license period, the entire pressure boundary is monitored over time. The frequency of these tests depends on which option (A or B) is selected. With Option A, testing is performed on a regular fixed time interval as defined in 10 CFR Part 50, Appendix J. In the case of Option B, the interval for testing may be adjusted on the basis of acceptable performance in meeting leakage limits in prior tests. Additional details for implementing Option B are provided in NRC RG [Regulatory Guide] 1.163 and NEI 94-01.

The staff noted that the applicant's TS, referencing the 10 CFR Part 50, Appendix J, Testing Program, state that the performance characteristics of the program are implemented in accordance with Amendment 135 to the Operating License. The staff's SER for Amendment 135, dated April 6, 1998, states, contrary to the applicant's basis and LRA documents, that the applicant does not use NRC RG 1.163, "Performance-Based Containment Leak-Test Program," which establishes the performance criteria per GALL Report AMP XI.S4, for "10 CFR Part 50, Appendix J, Program," for implementation of Option B. To resolve this inconsistency, by letter dated August 15, 2012, the staff issued RAI B.1.15-2 requesting that the applicant identify the exceptions and/or enhancements needed to make the program consistent with the GALL Report and further identify whether the program should be either evaluated as:

(1) consistent with exceptions,
(2) consistent with enhancements, or
(3) consistent with exceptions and enhancements.

In the event that the program is not consistent, consistent with exceptions, or consistent with enhancements with the GALL Report, the staff requested the applicant to expand the summary description of the program sufficiently, so it can be reviewed as a plant-specific program.

In its response dated September 13, 2012, the applicant stated that the Containment Leak Rate Program is in accordance with the provisions of 10 CFR Part 50, Appendix J, Option B. Its procedures delineate the requirements for Types A, B and C leakage rate testing based upon the criteria in RG 1.163, NEI 94-01, "Industry Guidance for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J," and ANSI 56.8-1994, "Containment System Leakage Testing Requirements." The applicant also stated that the amendment request (Amendment 135) proposed to use the guidance described in an NRC SER rather than RG 1.163, as the method of implementing Appendix J, Option B. The applicant further stated that the NRC SER was for an exemption requested from Appendix J, Option A and granted on April 26, 1995. The approval of Amendment 135 permitted the applicant to implement the containment leak rate testing provisions using Option B in lieu of Option A.

The staff reviewed the applicant's response and noted that the applicant stated that currently its plant procedures are in accordance with the provisions of 10 CFR Part 50, Appendix J, Option B for Types A, B and C leakage rate testing based upon the criteria in RG 1.163, NEI 94-01, and ANSI 56.8. The staff also reviewed the April 6, 1998, letter to Mr. Joseph Hagan of Entergy regarding the issuance of Amendment No. 135 and letter of April 26, 1995, to Mr. Randy Hutchinson, of Entergy, regarding the SER for the 10 CFR Part 50, Appendix J, requested exemption. The staff noted that the applicant addressed its "plant-specific needs" with a plant-specific submittal, which the NRC determined was consistent with the intent of RG 1.163 and, therefore, was acceptable. GALL Report AMP XI.S4, to which the applicant claims consistency, recommends applicants follow RG 1.163, NEI 94-01, Revision 2-A, and the referenced ANSI/ANS-56.8-2002 as the current proper guidelines for acceptable 10 CFR Part 50, Appendix J, testing. Although the applicant's response states that its program is based upon the criteria in RG 1.163, NEI 94-01, and ANSI 56.8, these documents are not in the UFSAR supplement. This level of detail is necessary in the UFSAR to ensure the program is properly implemented during the period of extended operation. The staff discussed this issue with the applicant in a conference call on November 20, 2012. The applicant stated that it would supplement the response to RAI B.1.15-2 to include a revised Section A.1.15 of the UFSAR supplement for the containment leak rate program. By letter dated December 18, 2012, the applicant supplemented its response to RAI B.1.15-2 and revised LRA Sections A.1.15 and B.1.15 to include references to RG 1.163, NEI 94-01, and ANSI 56.8.

The staff finds the applicant's response to RAI B.1.15-2 acceptable because the applicant's Containment Leak Rate Program is consistent with the GALL Report, RG 1.163, NEI 94-01, and ANSI 56.8R. In addition, the applicant has provided sufficient details of the program in the UFSAR supplement.

Based on its audit, and review of the applicant's responses to RAI B.1.15-1 and RAI B.1.15-2, 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.S4.

Operating Experience. LRA Section B.1.1.15 summarizes operating experience related to the 10 CFR Part 50, Appendix J, Program. The LRA states that LLRTs during RF10 through RF15 met test acceptance criteria. However, some components failed to meet the administrative limits. Some of these were repaired and retested as acceptable, while others were evaluated and deferred. In each of these cases, the containment leakage was within overall allowed limits. Noteworthy operating experience examples in the LRA include:

- A 2006 test of the containment isolation valves failed (penetration #35). Their LLRT indicated a flow of 3487 sccm leakage. The allowable limit was 3400 sccm. The leakage was found acceptable through additional engineering evaluation.
- A 2008 test of the filter/demineralizer system containment isolation valves (penetration #49). The test indicated a leakage rate approximately 12 times the administrative limit. After flushing the system, the valves were re-tested satisfactorily. For these valves, a new procedure was established ensuring that a system flush will be completed satisfactorily after future resin transfers.
- Successful ILRT performed in 2008 that confirmed the structural integrity of the containment.

The LRA states that operating experience indicates that the program is effective at identifying and managing aging effects on primary containment components. The LRA also states that a program self-assessment in 2009 revealed a decline in performance due to organizational weaknesses. The LRA further states that follow-up actions from the 2009 self-assessment, however, indicate improved data analyses and performance monitoring and that reviews against established program standards provide assurance that the program will remain effective for managing loss of material of components.

The staff also followed-up on the 2009 program self-assessment and reviewed a 2010 assessment, "Cornerstone Rollup, Program: Appendix J," which reaffirmed the decline and attributed it to knowledge gap, lack of experience of the program owner, declines in program personnel, and declines in infrastructure, implementation, and equipment. The staff, however, noted that the applicant has taken steps to assure satisfactory program performance, including:

- internal reviews of program's performance against established standards to assure program effectiveness against loss of material of components
- plant-specific operating experience evaluation including the identification of degradation leading to corrective action(s) when necessary prior to loss of intended function providing evidence that the program is effective for managing aging effects of components
- program owner contributions identifying program success and weakness

- applicable self-assessments, QA audits, peer evaluations, and NRC reviews
- event investigations, trending reports, lessons learned from in-house events, self-assessments, including the 10 CFR Part 50, Appendix B corrective action process
- industry operating experience evaluations and actions to mitigate the consequences where applicable

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.15 provides the UFSAR supplement for the Containment Leak Rate 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 applicant's UFSAR needed to be augmented to indicate that the plant procedures for Types A, B and C leakage rate testing will be implemented in accordance with the criteria set in RG 1.163, NEI 94-01, Revision 2-A, and ANSI/ANS-56.8-2002, which are the most current guidelines for acceptable LRTs. 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 December 18, 2012, the applicant revised its UFSAR supplement to include these documents. As discussed above in response to RAI B.1.15-2, the staff reviewed the supplement and found it acceptable because it includes an acceptable level of detail and incorporates the appropriate documents. The staff's concern is resolved, and the staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Update to LRA AMP B.1.15.</u>

By letter dated September 23, 2016, the applicant revised LRA Section B.1.15, "Containment Leak Rate," aging management program. The letter summarized events that led to changes to the LRA AMP, Containment Leak Rate program, as follows:

> On February 17, 2016, the NRC staff approved (ADAMS Accession No. ML16011A247) a Grand Gulf license amendment request [LAR] (ADAMS Accession No. ML15147A599) to adopt NEI 94-01, Revision 3-A, subject to specific conditions and with partial implementation of ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements," as the implementing document for Type B and Type C leak rate testing (LRT).

Following the NRC approval of the Grand Gulf LAR (License Amendment 209), and further discussions by the NRC staff with the applicant on this issue, NRC was notified of changes affecting LRA AMP B.1.15, "Containment Leak Rate" program. In its letter dated September 23, 2016, the applicant stated that approval and implementation of the LAR did not alter its conclusion of the program's consistency with that of the GALL Report, Revision 2, AMP XI.S4, as was indicated in the original submittal of the LRA on October 28, 2011. However, by letter dated October 3, 2016, the applicant supplemented its September 23rd letter and submitted a revised LRA AMP B.1.15, which takes exceptions to the GALL Report AMP XI.S4 recommendations for the "monitoring and trending" and "corrective actions" program elements.

The staff considers the stated exceptions to "monitoring and trending" and "corrective actions" program elements as being portions of the GALL Report AMP XI.S4 that the applicant does not intend to implement. The SRP-LR states that an applicant may take one or more exceptions to specific GALL Report AMP elements, and that any exception should be described and justified. The staff reviewed the technical justifications for the exceptions, including associated OE from the NRC-approved LAR, and assessed whether the revised LRA AMP B.1.15 is adequate to manage the effects of aging for SSCs within the scope of the Containment Leak Rate program. The staff's evaluation of these exceptions is as follows:

Exception 1. The revised LRA Section (AMP) B.1.15 states an exception to the "monitoring and trending" program element. In this exception, the applicant stated the revised LRA AMP B.1.15 follows NEI 94-01, Revision 3-A, subject to conditions specified in the safety evaluation (SE) report for Grand Gulf LAR dated May 27, 2015, to establish the local leak rate testing frequency for its Containment Leak Rate program instead of Revision 2-A of the NEI 94-01 referenced in the "monitoring and trending," program element of the GALL Report AMP XI.S4.

The noted difference between NEI 94-01, Revision 2-A and NEI 94-01, Revision 3-A is in the testing frequency of Type C (containment isolation valve [CIV] leakage rates) LLRTs. RG 1.163 and NEI 94-01, Revision 2-A, limit the testing interval for Type C tests to 60 months with a grace period (permissible extension for non-routine emergent conditions) of up to 15 months, while NEI 94-01, Revision 3-A, extends the testing interval for Type C tests to 75 months and reduces the grace period to nine months. For Type B tests, although the maximum testing interval remains unchanged (120 months), the grace period under NEI 94-01, Revision 3-A is also reduced to nine months.

The staff reviewed this exception to LRA AMP B.1.15, "monitoring and trending," program element against the corresponding program element in GALL Report AMP XI.S4 and finds it acceptable because when NEI 94-01, Revision 3-A is implemented there would be no negative impact when adjusting the testing interval for Type B and Type C tests based on their past acceptable local leakage rate performance, other "performance factors," and reduced grace periods as articulated in the SE of the approved LAR.

The staff reviewed the methodology to increase the testing interval of CIVs for leakage rate tests and noted that the February 17, 2016, NRC approved LAR resulting in Amendment 209 to the Facility Operating License considered the limitations and conditions imposed by the May 8, 2012, NRC approval of NEI 94-01, Revision 3-A in the context of 10 CFR Part 54. Specifically, when approving the LAR, the staff noted the "Performance Factors" (i.e., past performance, design and service life, safety impacts if failed, cause determination and programmatic controls) identified in Section 11.3.1 of NEI 94-01, Revision 3-A, that would contribute in adjusting the testing interval were considered. If reviews identified any age-related mechanisms contributing to leakage, "they were noted and recommendations were made concerning their impact on eligibility for the extended test interval of 75 months."

For the purposes of assessing and monitoring or trending the overall containment leakage potential, the as found minimum pathway leakage rates for the just tested penetrations are summed with the as-left minimum pathway leakage rates for penetrations tested during the previous 1, 2 or 3 refueling outages. For CIVs, the entire population subject to LLRT is evaluated based on three consecutive as-found leak rate tests to identify successful past performance when considering extensions to the testing interval. Furthermore, for each Type C component on a greater than 60-month test interval, the applicant will apply a potential leakage understatement adjustment factor of 1.25 to the actual as-left leak rate, which will increase the as-left leakage total. The staff noted in the SE of the approved LAR, that the applicant monitored the performance of the Type B and Type C tests over a nine year period (2005 through 2014) and concluded based on compiled data the high of "as-found" minimum pathway and the "as-left" maximum pathway to have adequate margins of 12.35% and 47% respectively, compared to the regulatory maximum leakage rate at calculated peak containment internal pressure related to design basis accidents.

The staff also noted, implementation of the approved LAR does not change the periodic inspections of the external surfaces of containment penetrations performed in accordance with AMP B.1.13, "Containment Inservice Inspection – IWE," or by any of the other proposed LRA AMPs selected by the applicant to manage the effects of aging of the components excluded from 10 CFR Part 50, Appendix J testing, as discussed above. Similarly, implementation of the approved LAR does not affect the scheduling of Type B tests as reflected in the approved LAR, unless affected by the aforementioned "Performance Factors." Furthermore, the staff noted scheduling for Type C components currently not on an extended testing interval follows the current schedule until their eligibility for an extended testing interval based on leakage rate tests can be determined.

The staff also noted that following a one time extension approved in 2004 (ADAMS Accession No. ML040300152) in the testing interval of Type A test (ILRT) to 15 years, the testing interval for Type A tests currently remains at 10 years, consistent with the guidance in RG 1.163. The staff therefore concludes that implementation of NEI 94-01, Revision 3-A in lieu of the NEI 94-01, Revision 2-A poses no negative impact in the acceptance of the "monitoring and trending" program element.

Exception 2. The revised LRA Section (AMP) B.1.15 states an exception to the "corrective actions" program element. In this exception, the applicant stated corrective actions in the revised LRA AMP B.1.15 are taken in accordance with 10 CFR Part 50 Appendix J and NEI 94-01, Revision 3-A, subject to the conditions specified in the safety evaluation (SE) report for Grand Gulf LAR dated May 27, 2015, when leakage rates do not meet those established in the plant's Technical Specifications in lieu of Revision 2-A of NEI 94-01, referenced in the "corrective actions," program element of the GALL Report AMP XI.S4.

The staff verified that the NRC approval of the Grand Gulf LAR resulted in changes to Technical Specifications (initially discussed above in the main body of the AMP) affecting Type B and Type C tests. These recent changes to the Technical Specifications constitute a part of the plant's CLB regarding the implementation of 10 CFR Part 50, Appendix J.

The staff noted differences in NEI 94-01, Revision 3-A (now credited for the Containment Leak Rate Program) and NEI 94-01, Rev 2-A (recommended by the GALL Report, Revision 2, AMP XI.S4). Specifically, the staff noted that in addition to record keeping requirements of Section 12.1, "Report Requirements," of NEI 94-01, Rev 2-A, NEI 94-01, Revision 3-A augmented the record keeping to include adverse trends in leakage rate summation of Type B and Type C components and the development of a corrective action plan to restore the leakage rate summation margin to an acceptable level.

The staff reviewed this exception to LRA AMP B.1.15, "corrective actions," program element against the corresponding program element in GALL Report, AMP XI.S4 and finds it acceptable because when NEI 94-01, Rev 3-A is implemented there would be no negative impact in the corrective actions program element considering the added review for adverse trends in leakage rate summation for Type B and Type C tests and existing "cause determination," imposed by the "Performance Factors," discussed in *Exception 1* above, that includes identification of failures during an extended testing interval, and of the corresponding corrective actions to be taken.

The staff noted the NRC approval of the Grand Gulf LAR also addressed relevant OE associated with the "corrective action," program element. Specifically, valves that failed to meet the LLRT administrative limits during two consecutive refueling outages (RF), RF-18 and RF-19

> "would be tested on the minimum test interval until two successful tests were recorded … [and] the licensee created an action to investigate the cause of any failed LLRTs … and documented corrective actions that will help ensure accurate record maintenance in the future."

The staff also noted that the addition to section 12.1 of NEI 94-01, Revision 3-A of "the margin between the Type B and Type C leakage rate summation and its regulatory limit," constitutes an enhancement to the "administrative controls," program element that supports the implementation of the "corrective actions," program element and further supports its acceptance. The staff therefore concludes for the purpose of corrective actions, implementation of NEI 94-01, Revision 3-A, in lieu of the NEI 94-01, Revision 2-A, poses no negative impact in the acceptance of the "corrective actions" program element.

Based on the above review of the exceptions associated with the "parameters monitored or inspected," and "corrective actions," program elements and their justifications, the staff finds that the LRA AMP B.1.15, with exceptions, is consistent with GALL Report AMP XI.S4, and adequate to manage the applicable aging effects.

<u>Update to LRA A.1.15 UFSAR.</u>

The staff reviewed the revised UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0.1, "FSAR Supplement for Aging Management of Applicable Systems," and noted that it is consistent with the implementing documents identified in the NRC staff approval of a Grand Gulf license amendment request dated February 17, 2016, and hence acceptable.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Containment Leak Rate 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.S4. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with exceptions, 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 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 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 Diesel Fuel Monitoring

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.16 describes the existing Diesel Fuel Monitoring Program as consistent, with enhancements, with GALL Report

AMP XI.M30, “Fuel Oil Chemistry.” The applicant stated that the program manages loss of material and fouling in piping and components exposed to an environment of diesel fuel oil by verifying the quality of fuel oil and controlling fuel oil contamination as well as periodic draining, cleaning, and inspection of tanks.

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 elements of GALL Report AMP XI.M30.

The staff also reviewed the portions of the “detection of aging effects” program element 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.1.16 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the program will be enhanced to include a 10-year periodic cleaning and internal inspection of the fire water pump diesel fuel oil tanks (SP64A002A/B), the diesel fuel oil day tanks for Divisions I, II, and III, and the diesel fuel oil drip tanks for Divisions I and II. The applicant stated that the cleaning and internal inspections will be performed at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals. Furthermore, the applicant stated that if visual inspection is not possible, a volumetric inspection will be performed. After reviewing this enhancement, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

GALL Report AMP XI.M30 recommends draining and cleaning of diesel fuel oil tank internal surfaces at least once every 10 years during the period of extended operation. During its audit, the staff found that the applicant’s program did not include the procedures for performing cleaning and inspection of the above-mentioned tanks. That is, the staff was not clear on the cleaning and inspection approach for these tanks. By letter dated June 22, 2012, the staff issued RAI B.1.16-2 requesting that the applicant provide a summary of the process for performing cleanings and internal visual inspections of the fire water fuel oil tanks, the diesel fuel oil day tanks, and the diesel fuel oil drip tanks in scope of the program.

In its response dated July 23, 2012, the applicant stated that each diesel fuel oil tank is first emptied to perform inspections. Sediment or sludge is removed and the tank internal surfaces are cleaned to provide a surface capable of visual inspection by qualified personnel.

The applicant stated that the tanks are then visually inspected for rust deposits, corrosion, or any obvious physical defects such as blisters, peeling, or pinholes. The applicant also stated that physical defects are documented and if evidence of degradation is observed during inspection, the affected area of the diesel fuel tank is volumetrically inspected. In addition, the applicant stated that if visual inspection is not possible, the diesel fuel tank is volumetrically inspected.

The staff finds the applicant’s response acceptable because it is consistent with the recommendations in GALL Report AMP XI.M30 and will allow for the degradation to be evaluated. The staff’s concern described in RAI B.1.16-2 is resolved.

The staff reviewed this enhancement against the corresponding program element 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 2. LRA Section B.1.16 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the program will be enhanced to include a volumetric examination of affected areas of the diesel fuel tanks if evidence of degradation is observed during visual inspection. The scope of this enhancement includes the diesel fuel oil day tanks (Divisions I, II, III), the diesel fuel oil storage tanks (Division I, II, III), the diesel fuel oil drip tanks (Divisions I, II), and the diesel fire pump fuel oil storage tanks, and is applicable to the inspections performed during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals. 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.

Summary. Based on its audit, and review of the applicant’s response to RAI B.1.16-2 of the applicant’s Diesel Fuel Monitoring Program, the staff finds that program elements one through six 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 “detection of aging effects” program element and finds that when implemented the enhancements will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.16 summarizes operating experience related to the Diesel Fuel Monitoring Program.

The applicant stated that in 2004, the standby diesel fuel oil storage tank (Division I, II) indicated tank internal surfaces were satisfactory. The applicant further stated that in 2005, sampling of the fire water diesel fuel oil storage tanks indicated no signs of water or foreign material in the tanks and that absence of aging effects indicates that the preventive actions of the program have been effective.

The applicant stated that in 2003, inspection of the HPCS (Division III) diesel fuel oil storage tank indicated small blemishes in the coating. The applicant stated that indications were corrected before the tank was returned to service.

The applicant reported that in 2005 samples from the fire water diesel fuel oil day tanks measured biological growth on day 3 of a 6-day incubation period. The applicant stated a biocide addition was performed.

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 AMP 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. Further, the staff found that routine sampling and biocide addition demonstrates the effectiveness of the 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 and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.16 provides the UFSAR supplement for the Diesel Fuel 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 the LRA does not specify the industry standards used for this 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 June 22, 2012, the staff issued RAI B.1.16-1, requesting that the applicant justify the absence of the industry standards used for the program in the UFSAR supplement and the program description in LRA Appendix B for the Diesel Fuel Monitoring Program.

In its response dated July 23, 2012, the applicant stated that the acceptance criteria for fuel oil quality parameters are as invoked or referenced in the plant's TS. As result, the applicant revised LRA Sections A.1.16 and B.1.16 to include the following statement: "Acceptance criteria for fuel oil quality parameters are specified in the GGNS [Grand Gulf Nuclear Station] technical specifications." The staff's concern described in RAI B.1.16-1 is resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated July 23, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Diesel Fuel 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 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.16 Environmental Qualification (EQ) of Electric Components

Summary of Technical Information in the Application. LRA Section B.1.17 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 GGNS EQ Program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods.

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 elements of GALL Report AMP X.E1.

The staff also reviewed a main steam isolation valve (MSIV) limit switch recalculation. The recalculation demonstrated the qualified life of limit switches associated with the MSIVs due to an extended power uprate. This recalculation is being issued to justify the deferral of the replacement of the MSIV limit switches from RF18 to RF19. The staff determined that the recalculation confirmed adequate safety margin exists in the qualified life of the limit switches.

The staff questioned the applicant during the audit regarding the frequency and methodology for walkdowns to ensure EQ environments have not changed. The applicant provided the staff with its TS for containment average temperature to ensure that the environment in which EQ equipment are located are monitored to detect any adverse localized environment that may accelerate aging and reduce the qualified life of EQ equipment.

Based on its audit and review of the application, the staff finds that program elements one through six 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.1.17 summarizes operating experience related to the Environmental Qualification (EQ) of Electric Components Program. The applicant stated a program assessment in 2009 confirmed compliance with 10 CFR 50.49 and measured the effectiveness of the program by evaluating the program's overall infrastructure, records, documentation, program implementation, support personnel qualification and knowledge, and the program's impact on plant equipment. According to the applicant, areas of weaknesses were addressed and follow-up actions were assigned to improve program effectiveness. During its audit, the staff reviewed EQ health reports dated back to 2006 and identified trends in the health reports that showed the applicant corrected the issues 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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.17 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 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 applicant's 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).

3.0.3.1.17 External Surfaces Monitoring

Summary of Technical Information in the Application. LRA Section B.1.18, as amended by letter dated May 13, 2014, describes the existing External Surfaces Monitoring Program as consistent, with enhancements, with GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." The LRA states that the AMP proposes to manage aging effects through visual inspections of external surfaces for evidence of loss of material, cracking, and change in material properties. The LRA also states that physical manipulation is used to detect hardening or loss of strength for elastomers and polymers. In the letter of May 13, 2014, the applicant amended the program description to indicate that, for a representative sample of indoor insulated components operated below the dew point, insulation will be removed for inspection of the component surface. The applicant stated that these inspections will be conducted during each 10-year period during the period of extended operation. There are no in-scope outdoor insulated mechanical components.

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.M36.

The staff also reviewed the portions of the "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.

Enhancement 1. LRA Section B.1.18 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 the AMP will be enhanced to include instructions for monitoring aging effects for flexible polymeric components through manual or physical manipulation of the material, with a sample size for manipulation of at least 10 percent of available surface area. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M36 and finds it acceptable because when it is implemented it will ensure the program includes manual or physical manipulation of at least 10 percent of the available surface area of polymeric materials, which is consistent with the GALL Report recommendations for managing changes in material properties for flexible polymeric materials.

Enhancement 2. LRA Section B.1.18 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that it will clearly identify underground components, which are in the scope of the program and have physical restrictions to access, in the program documents. The applicant also stated that instructions will be provided for inspection of all underground components within the scope of this program during each 5-year period, beginning 10 years prior to the entry into the period of extended operation. GALL Report AMP XI.M36 recommends that underground components be clearly identified in the program scope, and inspections of underground components be performed during each 10-year period beginning 10 years prior to the period of extended operation. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M36 and finds it acceptable because when it is implemented it will ensure underground components are clearly identified in the program, which is consistent with the GALL Report recommendations, and ensure inspections of underground components are conducted at least as frequently as recommended in GALL Report AMP XI.M36.

Enhancement 3. By letter dated May 13, 2014, the applicant added an additional enhancement to the "detection of aging effects" program element in order to manage "corrosion under insulation." The staff noted that the applicant adopted the recommended basis for managing "corrosion under insulation," GALL Report AMP XI.M36, as modified in LR-ISG-2012-02. The staff finds this enhancement to the program acceptable because it is consistent with the condition monitoring basis for managing "corrosion under insulation" in the update of the "detection of aging effects" elements of GALL Report AMP XI.M36, "External Surfaces Monitoring," as given in LR-ISG-2012-02.

The staff noted that, in the applicant's response to RAI 3.0.3-1, as given in the letter of May 13, 2014, the applicant found that the design of the GGNS does not include: (a) any outdoor, in-scope, insulated piping or piping components (mechanical components), (b) any outdoor, in-scope insulated tanks, or (c) any indoor, in-scope, insulated tanks operated at temperatures below the dew point. The staff noted that the basis in LR-ISG-2012-02 for managing "corrosion under insulation" is only applicable to in-scope, indoor, insulated piping or piping components that are operated below the dew point, where condensation may occur between the external surfaces of the components and the internal surfaces of the associated insulating materials. The staff finds the applicant response to RAI 3.0.3-1 acceptable because the applicant's basis is consistent with the recommendations for managing "corrosion under insulation" in Section E of LR-ISG-2012-02. RAI 3.0.3-1 is resolved.

Summary. Based on its audit of the applicant's External Surfaces Monitoring Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M36. 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.1.18 summarizes operating experience related to the External Surfaces Monitoring Program. The LRA states an operating experience example in which a loss of coating that resulted in surface corrosion was discovered on the tailpipe of a discharge safety relief valve during a walkdown. The LRA states that the corrosion did not affect the ability of the piping to perform its intended function and it was repaired using the normal work process. The LRA states another operating experience example in which pitting corrosion was detected on piping during replacement of the heat trace. The LRA states that the pitting did not threaten the integrity of the piping and was repaired. The LRA states another operating experience example in which build-up of scale and rust was found on an SSW valve bonnet. The LRA states that the rust and scale was removed during the inspection and the valve bonnet was found to be capable of performing 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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.18, as modified by letter dated May 13, 2014, provides the UFSAR supplement for the External Surfaces 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 3.0-1, as modified by LR-ISG-2012-02. The staff also noted that the applicant committed (Commitment No. 9) to enhancing the External Surfaces Monitoring Program to:

- include instructions for monitoring aging effects for flexible polymeric components through manual or physical manipulation of the material, with a sample size for manipulation of at least 10 percent of the available surface area
- identify underground components that are within the scope of the program in the program documents
- provide instructions for inspection of all underground components within the scope of the program during each 5-year period, beginning 10 years before entry into the period of extended operation
- address corrosion for insulated components by conducting periodic inspections of a representative sample during each 10-year period by considering the likelihood of corrosion under insulation,

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 applicant's External Surfaces 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 through Commitment No. 9 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.18 Fatigue Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.19 describes the existing Fatigue Monitoring Program as consistent, with an exception and enhancements, with GALL Report AMP X.M1, "Fatigue Monitoring." The LRA states that the program ensures that fatigue usage remains within allowable limits by (a) tracking the number of critical thermal and pressure transients for selected components, (b) verifying that the severity of monitored transients are bounded by the design transient definitions for which they are classified and

(c) assessing the impact of the reactor coolant environment on a set of sample critical components.

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 seven of the applicant's program to the corresponding program elements of GALL Report AMP X.M1. For the program description and the "parameters monitored or inspected," "monitoring and trending," and "corrective actions" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

During its audit, the staff reviewed the applicant's program basis document and implementing procedure and noted that it relies on tracking the number of critical thermal and pressure transients to ensure that fatigue usage remains within allowable limits. The staff noted that the applicant's program and implementing procedure uses several different methods for managing metal fatigue that are not described in LRA Sections B.1.19 and A.1.19 and the program basis document. The details of how the program manages metal fatigue, including environmental effects when applicable, are not clear to the staff. By letter dated April 4, 2012, the staff issued RAI B.1.19-1 requesting the applicant to describe the monitoring methods used by its program to manage metal fatigue. The applicant was also asked to describe whether a particular monitoring method will be used for certain components and fatigue evaluations or whether the methods will be used collectively.

In its response dated May 3, 2012, the applicant described each monitoring method used by its program and confirmed that there are no plans to use any methods other than cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring. The staff's review of each monitoring method is discussed below.

The applicant stated that for cycle-counting, plant data, such as reactor pressure, FW temperature, jet pump flowrate, and generator output, are monitored and saved in computer files for evaluation during periodic cycle tracking updates. During these updates, the number of transients that occurred during the time period between updates is determined and logged. The applicant stated that the logging of partial cycles is not used and only full cycles are recorded in the periodic cycle tracking updates. The staff finds it conservative that the applicant records transients as "full cycles" because the severity of actual transients is typically less than the design transient definition; thus, this equates to a lower actual accumulated fatigue usage than compared to the design assumption. The applicant stated that the numbers of cycles that have occurred are compared to limits corresponding to the allowable values used in associated fatigue analyses. The staff finds the use of cycle counting to be capable of managing metal fatigue because it ensures that the assumptions used in a fatigue evaluation remain valid; thus, ensuring the design limit is not exceeded.

The applicant stated that for cycle-based fatigue monitoring, it counts the cycles that have occurred and then computes the usage factor for a given location based on the design usage attributable to each individual transient cycle. The applicant stated that this method allows the determination of cumulative fatigue usage for a specific location based on the actual number of transient occurrences and the assumption that the fatigue usage contributed by each transient is equal to the design transient severity. Furthermore, the applicant indicated that events that are more severe than the design transients have been evaluated, and the resulting fatigue usage has been included in the cumulative fatigue usage at affected locations. The staff noted that the applicant's program includes corrective actions that address the issue when actual transient severity exceeds design transient severity, which is consistent with the "detection of aging effects” program element of GALL Report AMP X.M1. The staff finds the use of cycle-based fatigue monitoring to be capable of managing metal fatigue because it periodically calculates cumulative fatigue usage based on the cycle counts and design transient severity to ensure the design limit is not exceeded through the period of extended operation.

The applicant stated that stress-based fatigue monitoring is used where more refined fatigue estimates are necessary because of the more severe thermal duty specific components experience. This approach uses computer-based analyses and actual plant data to calculate the actual stress that occurs during each transient and the associated fatigue usage. The staff noted that the use of actual plant data such as local pressure and thermal condition to calculate actual fatigue usage is consistent with the “parameters monitored or inspected” program element of GALL Report AMP X.M1. The staff finds the use of stress-based fatigue monitoring to be capable of managing metal fatigue because it periodically calculates cumulative fatigue usage based on the conditions that are actually occurring at the applicant’s site during transients to ensure the design limit is not exceeded through the period of extended operation. The applicant addressed the concerns documented in Regulatory Issue Summary (RIS) 2008-30, “Fatigue Analysis of Nuclear Power Plant Components,” in its response to RAI B.1.19-2, which the staff evaluated below.

The applicant stated that if cycle-counting alone does not demonstrate that an analysis will remain valid, cycle-based fatigue monitoring or stress-based fatigue monitoring will then be used. The applicant explained that specific types of analyses, such as environmentally-assisted fatigue (EAF) or high-energy line break (HELB) analyses, do not exclusively use one particular method of fatigue monitoring. The staff noted that cycle counting is the simplest monitoring method and it is typically relied upon because it is very effective in ensuring that fatigue evaluations remain valid. If this method is no longer the most efficient, the applicant can use more detailed determination of cumulative fatigue usage and CUF by cycle-based or stress-based fatigue monitoring. The applicant clarified that stress-based fatigue monitoring is only currently used for the FW nozzle, the HPCS nozzle, and the FW weldolets. The staff finds the applicant’s use of the combination of these monitoring methods for all components to be conservative because each method, starting with cycle-counting to cycle-based fatigue to stress-based fatigue, progressively provides a more refined monitoring approach to manage metal fatigue and ensures that the applicable allowable limits are not exceeded.

The staff finds the applicant’s response to RAI B.1.19-1 acceptable because the applicant (1) clarified how each monitoring method ensures that metal fatigue is managed through the period of extended operation, which the staff evaluated above, and (2) is conservatively using a combination of three monitoring methods to manage metal fatigue. The staff’s concern described in RAI B.1.19-1 is resolved.

The “parameters monitored or inspected” program element of GALL Report AMP X.M1 states that the program monitors all plant design transients that cause cyclic strains, which are significant contributors to the fatigue cumulative usage factor (CUF_{en}). It is not clear to the staff, whether the “specific system/component cycles” referenced in the applicant‘s implementing procedures are or will be monitored. In addition, the staff noted that several documents (e.g., UFSAR, TS, and LRA) contain information related to the design transients and that in some instances the number of assumed cycles in these documents are not consistent. By letter dated April 4, 2012, the staff issued RAI B.1.19-6 requesting the applicant to confirm that the transient cycles monitored by its program include all transients with the most limiting cycle limit used in the determination of CUFs in ASME Code fatigue, HELB, and EAF evaluations. In addition, the applicant was requested to justify any transients used in these calculations that will not be monitored and tracked by the Fatigue Monitoring Program.

In its response dated May 3, 2012, the applicant confirmed that the transient cycles that will be monitored and tracked by the Fatigue Monitoring Program include the transients used in the determination of CUFs, except those discussed below, in ASME Code fatigue evaluations and HELB evaluations and the transients that will be used in EAF evaluations. In addition, the applicant confirmed that the most limiting cycle limit for a particular design transient that was or will be used in any fatigue analysis will be monitored and tracked to ensure that action is taken before any applicable fatigue analysis becomes invalid. The staff's evaluation of transients not monitored by the Fatigue Monitoring Program is discussed below.

The staff finds it appropriate that the applicant is monitoring and tracking the transients in the fatigue evaluations discussed above because this ensures that the assumptions used to calculate the CUF remain valid and that the transients that contribute to fatigue usage do not exceed the allowable limit during the period of extended operation. The staff finds it acceptable that the applicant is monitoring and tracking the most limiting cycle limit for a particular design transient that was or will be used in a fatigue analysis because this ensures that the assumptions in any fatigue analysis or an allowable limit will be exceeded without taking preemptive corrective actions.

The applicant stated that the design cyclic transients for Class 1 components are defined by applicable design specifications for each component and are included as part of each component stress report. Furthermore, the overall set of plant design transients may be augmented by component-specific design transients to adequately bound the cycles expected at a specific location. The transients identified in the applicant's calculations that are not tracked but may contribute to fatigue usage are evaluated individually below.

The applicant stated that the daily reduction of 75 percent power and weekly reduction of 50 percent power transients are not tracked because its plant is a base-loaded plant that does not perform these power reductions. The staff noted that the design number of events for a load-following plant was assumed to occur for these transients even though the applicant's site does not practice load-following operation. Since these transients were meant for a plant designed for load-following operation, the staff finds it reasonable that the above-mentioned transients are not monitored because the applicant's site does not practice load-following operation and operates as a base-loaded plant.

The applicant stated that the control rod patterns change transient is a reduction of power and the total number of power reductions used in the analyses is far more than what is required to bound the actual plant operation. The staff noted that this transient does not cause a temperature or pressure change that would cause significant cyclic stress to the applicable components. The staff also finds it reasonable that this transient does not need to be monitored because, without significant cyclic stress caused by this transient, fatigue usage is not incurred.

The applicant stated that the CRD return nozzle hydraulic system return nozzle transient is not tracked because this nozzle was capped. The staff confirmed in UFSAR Section 5.3.3.1.1.4.5.1 that the CRD return nozzle hydraulic system return nozzle has been capped; therefore, the staff finds it acceptable that the applicant does not monitor this transient because the return line and nozzle are no longer used. In addition, the applicant stated that the head cooling spray nozzle is not tracked because head cooling spray is not used at its site. The staff confirmed in the UFSAR and LRA Section 2.3.2.1 that the head spray line has been functionally abandoned;

therefore, the staff finds it acceptable that the applicant does not monitor this transient because this piping line and nozzle is no longer used to perform head cooling spray. Furthermore, the applicant stated that the core differential pressure and SLC nozzle transient is not tracked because its injection path has changed such that this nozzle is not used for this injection. The staff confirmed in UFSAR Section 3.9.5.1.2.7 that SLC injection has been rerouted to the HPCS discharge line. Therefore, the staff finds it acceptable that the applicant does not monitor this transient because it no longer occurs at this nozzle originally designed for the occurrence of SLC injection.

The staff finds the applicant's response to RAI B.1.19-6 acceptable because, consistent with the "parameters monitored or inspected" program element, the applicant is monitoring all plant design transients and the associated limiting number of cycles used in its fatigue evaluations (i.e., CUF, HELB, and CUF_{en}) that are significant contributors to the CUF_{en}. In addition, the staff finds the applicant's response acceptable because the applicant justified not monitoring specific transients, as described above. The staff's concern described in RAI B.1.19-6 is resolved.

The "monitoring and trending" program element of GALL Report AMP X.M1 states that trending is assessed to ensure that the CUF_{en} remains below the design limit during the period of extended operation. During its audit, the staff reviewed the program implementing procedure and noted that it relies on several different monitoring methods and only provides direction to generate a condition report that is based on the projected cumulative fatigue usage for a component. It is not clear to the staff whether the program includes or will include appropriate trending of appropriate parameters (e.g., cycles, CUF, CUF_{en}) based on the monitoring method. By letter dated April 4, 2012, the staff issued RAI B.1.19-3 requesting the applicant to discuss this discrepancy between the implementing procedure and the different monitoring methods of the program.

In its response dated May 3, 2012, the applicant stated that its program manages metal fatigue by tracking accrued transients against calculation assumptions and by calculating and trending CUFs by using cycle-based fatigue monitoring and stress-based fatigue monitoring. For cycle counting, the applicant stated the actual number of specific cycles that have occurred will be trended and action will be taken before the number of any individual transients exceeds the limit established in the analysis. The staff finds the applicant's timing for taking action for this method to be conservative because for the fatigue usage of a component to be equal to the calculated CUF all transients must have occurred at the assumed design limits in terms of occurrence and severity, not just one individual transient. For the cycle-based and stress-based fatigue monitoring, the applicant stated the parameter tracked is the cumulative fatigue usage based on transients that have occurred and action will be taken when the CUF is projected to exceed the allowable limits within the next 6 years. The staff finds the applicant's timing for taking action for these methods to be conservative because this approach provides sufficient time to plan and execute corrective actions based on the cumulative fatigue usage that is periodically calculated and projected to ensure an allowable limit is not exceeded.

The staff finds the applicant's response to RAI B.1.19-3 acceptable. The parameters monitored and trended by the applicant are appropriate for the monitoring method used and the applicant has set conservative action limits to ensure sufficient time to identify, plan, and execute necessary corrective actions, as described above. The staff's concern described in RAI B.1.19-3 is resolved.

The "corrective actions" program element of GALL Report AMP X.M1 recommends specific corrective actions if the acceptance criteria are exceeded, in addition to the requirements of

10 CFR Part 50, Appendix B. The applicant claimed to be consistent with the GALL Report; however, during its audit, the staff noted the applicant's corrective actions program is used to satisfy 10 CFR Part 50, Appendix B, but the recommendations from the GALL Report for repair, replacement, and reanalysis of the component and scope expansion were not included. In addition, since the applicant's Fatigue Monitoring Program will be enhanced to address EAF, it is not clear whether the applicant's program will ensure that if any changes or modifications occur in the future, the limiting locations will have been addressed for EAF. By letter dated April 4, 2012, the staff issued RAI B.1.19-4 requesting the applicant to justify the discrepancy between its claim of consistency with GALL Report AMP X.M1 and its program basis document. In addition, the applicant was requested to confirm that its program will continually ensure that the locations managed for EAF will remain limiting for its plant-specific configuration if any plant changes or modifications occur in the future.

In its response dated May 3, 2012, the applicant clarified that not specifically listing the acceptable corrective actions in GALL Report AMP X.M1 was not intended to eliminate them from consideration during evaluation of a condition that fails to meet the acceptance criteria. The applicant confirmed that repair, replacement, and re-evaluation are common corrective actions assigned under the CAP for many identified conditions at the plant. In addition, evaluation under the CAP is expected to consider scope expansion to include other locations with the highest expected CUFs when considering environmental effects. The applicant also stated that any additional cycle limits determined necessary to support EAF analyses will be added to the Fatigue Monitoring Program. The applicant confirmed that its modification procedures are relied upon to identify the appropriate design requirements for analysis of metal fatigue associated with plant changes or modifications. The applicant also confirmed that any additional cycle limits that must be monitored to support new design analyses will be added to the Fatigue Monitoring Program.

The staff finds the applicant's response to RAI B.1.19-4 acceptable because the applicant described and confirmed that the measures it takes as part of its corrective actions program are consistent with the recommendations in the "corrective actions" program element of GALL Report AMP X.M1. In addition, the staff finds the applicant's response acceptable because the applicant confirmed that its existing procedures would necessitate the evaluation of the design requirements, which include EAF, for analysis of metal fatigue if there are modifications to the plant. The staff's concern described in RAI B.1.19-4 is resolved.

The staff also reviewed the portions of the "scope of program," "detection of aging effects" and "corrective actions" program elements associated with the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception and these enhancements follows.

Exception. LRA Section B.1.19 states an exception to the "corrective actions" program element. In this exception, the applicant stated that the GALL Report recommends use of a design code limit for CUFs; however, it applies a more stringent design limit of 0.1 CUFs at HELB locations. Also, the applicant includes an additional corrective action to evaluate the HELB analysis to address a HELB exclusion location with a CUF that increases to greater than 0.1. In addition, the applicant clarified that the use of a 0.1 limit for CUF at HELB locations is consistent with the criteria stated in UFSAR Section 3.6A.2.

The staff noted that one of the criterions for determining HELB locations is based on calculated CUF values being less than a value of 0.1. This criterion is specified in the applicant's UFSAR for the determination of HELB locations.

The staff reviewed this exception against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because the Fatigue Monitoring Program is establishing a stricter acceptance criterion for HELB locations consistent with the applicant's UFSAR. In addition, the staff finds it appropriate that the applicant is using its Fatigue Monitoring Program to manage these HELB locations because the determination of these locations are based on the design transients monitored by the program and on CUF values that are also managed by this program.

Enhancement 1. LRA Section B.1.19 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that a review of its HELB analyses and the corresponding tracking of associated CUFs will be performed to ensure that the program adequately manages fatigue usage for these locations.

This program element of GALL Report AMP X.M1 states that the scope includes those components that have been identified to have a fatigue TLAA and ensures the fatigue usage remains within the allowable limit. The staff noted that the determination of HELB locations are based on the design transients and cumulative fatigue usage being managed by the Fatigue Monitoring Program; thus, the staff finds it reasonable that these HELB analyses and locations are included in the scope of this program.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant's program will include components that have a TLAA based on the design transients and cumulative fatigue usage and is being managed to ensure that the allowable limit of 0.1 is not exceeded, consistent with the "scope of program" program element.

Enhancement 2. LRA Section B.1.19 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that fatigue usage calculations that consider the effects of the reactor water environment will be developed for a set of sample reactor coolant system (RCS) components. This sample set will include the locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," and additional plant-specific component locations in the RCPB if they are found to be more limiting than those considered in NUREG/CR-6260. Environmental fatigue (F_{en}) factors will be determined using the formulae sets listed in LRA Section 4.3.3. By letter dated May 3, 2012, in response to RAI B.1.19-1, the applicant amended this enhancement to include the following, "[i]f necessary following this analysis, revised cycle limits will be incorporated into the Fatigue Monitoring Program documentation."

This program element of GALL Report AMP X.M1 states that for a set of sample sets of RCS components, fatigue usage calculations should consider the effects of the reactor water environment. In addition, this sample set includes the locations identified in

NUREG/CR-6260 and additional plant-specific component locations in the RCPB if they may be more limiting than those considered in NUREG/CR-6260.

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 include fatigue usage calculations that consider the effects of reactor coolant environment for a sample set of components, consistent with the "scope of program" program element. In addition, the staff finds it acceptable that revised cycle limits will be incorporated into the Fatigue Monitoring Program, if necessary, following the environmental fatigue analyses because this will ensure appropriate cycle limits are incorporated into the applicant's program to determine whether these analyses remain valid during the period of extended operation.

Enhancement 3. LRA Section B.1.19 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to revise program documents to provide updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components has been modified.

During its audit, the staff reviewed the applicant's implementing procedures for the Fatigue Monitoring Program and noted that the relation between the different monitoring methods is not apparent. Therefore, it is not clear to the staff what aspects of the program and procedures will be revised to account for the enhancement to the "detection of aging effects" program element. In addition, the enhancement is specific about updates to calculations when an allowable cycle limit is approached; however, since the program relies on different monitoring methods, it is also not clear if and when updates to calculations will be required for other parameters that are monitored. By letter dated April 4, 2012, the staff issued RAI B.1.19-7 requesting the applicant to describe how the implementing procedures for the program will be revised to implement this enhancement, considering that the program relies on several monitoring methods.

In its response dated May 3, 2012, the applicant stated that its program manages metal fatigue by counting cycles and by the calculation of cycle-based fatigue and stress-based fatigue CUFs. In order to address allowable cycle limits, implementing procedures will provide for updates of the fatigue usage calculations based on the monitoring method, which are as follows. For specific cycle logging, update of the fatigue analysis will be done prior to the number of any individual transient exceeding the limit analyzed for in the analysis. As previously discussed in the evaluation of RAI B.1.9-3 for this method, the staff finds the timing is capable of identifying the need to update fatigue calculations before the analysis becomes invalid in order to manage fatigue. The applicant stated that for the determination of cumulative fatigue usage for cycle-based and stress-based fatigue monitoring, action will be taken when the CUF is projected to exceed the allowable within the next 6 years. Also, as previously discussed in the evaluation of RAI B.1.9-3 for these methods, the staff finds the timing is capable of identifying the need to update fatigue calculations before the allowable limit is exceeded in order to manage fatigue.

The staff finds the applicant's response to RAI B.1.19-7 acceptable because (1) the parameters monitored and trended by the applicant are capable of determining when a fatigue evaluation may become invalid or if an allowable limit may be exceeded and (2) the action limits provide sufficient time for the applicant to identify, plan, and execute necessary corrective actions. The staff's concern described in RAI B.1.19-7 is resolved.

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 capable of determining when a fatigue evaluation may become invalid or if an allowable limit may be exceeded and the action limits will be set to provide sufficient time to provide updates of the fatigue usage calculations on an as-needed basis, consistent with the "detection of aging effects" program element. In addition, the staff finds it acceptable because when it is implemented the applicant's program will update its fatigue usage calculations if any inputs, such as a transient definition, new thermal events or component geometry, are changed, which is also consistent with this program element of the GALL Report.

By letter dated June 21, 2012, the applicant amended this enhancement to include a program revision to provide for the consideration of the recirculation pump fatigue analysis exemption validity if cycles that were input into the exemption evaluation exceed their limits. The applicant provided this amendment in response to RAI 4.3-11 related to its fatigue analysis for the Byron-Jackson reactor recirculation pump casing. The staff's evaluation of the applicant's response to RAI 4.3-11 is documented in SER Section 4.3. The applicant stated in its response that this exemption determination considered the assumed number of fatigue transients specified by GE.

The staff finds this amended portion of the enhancement acceptable because the applicant's Fatigue Monitoring Program will track the transients cycles assumed in the recirculation pump fatigue analysis exemption against the allowable numbers of cycles; thus, ensuring that this exemption for a fatigue analysis will remain valid during the period of extended operation. The staff noted that the applicant's program also include corrective actions, consistent with GALL Report AMP X.M1, if an allowable number of cycles is approached.

Summary. Based on its audit of the applicant's Fatigue Monitoring Program, and review of the applicant's responses to RAIs B.1.19-1, B.1.19-3, B.1.19-4, B.1.19-6 and B.1.19-7, the staff finds that program elements one through seven for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP X.M1. The staff also reviewed the exception associated with the "corrective actions" program element, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "scope of program" and "detection of aging effects" program elements and finds that when implemented, the AMP will adequately manage the applicable aging effects.

Operating Experience. LRA Section B.1.19 summarizes operating experience related to the Fatigue Monitoring Program. The LRA provides a discussion regarding an assessment the applicant performed in 2003, which found it to be effective in collecting plant operational data required for the calculation of fatigue usage factors. Data collected and trended through 1999 confirmed that the number of cycles was not trending toward exceeding the allowable number of cycles. In addition, the applicant stated that a 2011 study of its plant data showed that the number of plant transients to date were within their design allowable limits.

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 AMP 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 RAIs, as discussed below.

LRA Section 4.3.1.1 states that stress-based fatigue monitoring on the FW nozzle, the HPCS nozzle, and the FW weldolets is being used. The staff noted that as discussed in RIS 2008-30, there were concerns with a methodology used to perform fatigue calculations and as input for online fatigue monitoring programs by license renewal applicants or licensees in the current operating term. It is not clear how stress-based fatigue monitoring is currently incorporated and how it will be used to manage metal fatigue by the Fatigue Monitoring Program. It is also not clear how the applicant addressed the concerns identified in RIS 2008-30. By letter dated April 4, 2012, the staff issued RAI B.1.19-2 requesting the applicant to justify the actions taken for the period of extended operation to address the concerns described in RIS 2008-30 for any reanalysis that will use stress-based fatigue monitoring. In addition, the applicant was requested to justify the actions that have been taken to ensure that the potential nonconservative methods described in RIS 2008-30 have not challenged the ability to maintain the allowable limit for those locations that currently use stress-based fatigue monitoring.

In its response dated May 3, 2012, the applicant stated that EAF analyses will be completed before the period of extended operation and that any reanalysis to address the effects of the reactor coolant environment will use all six stress components for varying principal stress. The applicant confirmed that the issues discussed in RIS 2008-30 are being addressed in the CAP as a CLB issue under 10 CFR Part 50. As part of the corrective actions, Entergy will upgrade the stress-based fatigue monitoring software to analyze fatigue using all six stress components; thus, during the period of extended operation, any locations that use the stress-based fatigue method for the analysis of fatigue will use all six stress components. The staff finds it appropriate that the applicant reviewed the concerns discussed in RIS 2008-30 for applicability to its site and entered it into its corrective actions program for evaluation and resolution. In addition, the staff finds it acceptable that the applicant's use of stress-based fatigue monitoring will consider all six stress components as inputs for the varying principal stress because this is consistent with rules defined in ASME Code, Section III.

The applicant stated that based on its evaluation of RIS 2008-30 and industry experience, no immediate actions were found to have been needed to ensure that the allowable limit is maintained and that potential nonconservatisms in the analyses are not expected to result in significant changes to the extent that the calculated fatigue usage would be unacceptable. The staff noted that for the locations the applicant is using stress-based fatigue monitoring (i.e., FW nozzle, the HPCS nozzle, and the FW weldolets) the calculated CUF value is less than 1.0 and the current accumulated cycles for each transient is less than the number of occurrences postulated in the fatigue evaluations for these components. The staff noted that for the fatigue usage of a component to be to equal the calculated CUF, all transients must have occurred at the assumed design limits in terms of occurrence and severity, not just one individual transient. Therefore, the staff finds the applicant's determination not to take immediate actions regarding RIS 2008-30 to be reasonable.

The staff finds the applicant's response to RAI B.1.19-2 acceptable because its program was capable of (1) identifying and evaluating generic operating experience as being applicable to its site, (2) assessing the need as to whether any immediate actions were needed, as described above and (3) determining that long-term actions were needed to upgrade its fatigue monitoring software for the period of extended operation. The staff's concern identified in RAI B.1.19-2 is resolved.

The "operating experience" program element of GALL Report AMP X.M1 recommends that the program review industry experience relevant to fatigue cracking. The staff noted that RIS 2011-14 was issued on December 29, 2011, and is associated with the implementation of computer software packages used to demonstrate the ability of nuclear power plant components to withstand the cyclic loads associated with plant transient operations. During its audit, the staff noted that the applicant uses the computer software, FatiguePro, and it is not clear if the data collected by FatiguePro is reviewed and modified before the determination of cumulative fatigue usage for a component or of an accrued transient cycle. By letter dated April 4, 2012, the staff issued RAI B.1.19-5 requesting the applicant to describe and justify any actions that have been or will be taken to address the concerns described in RIS 2011-14. In addition, the applicant was requested to describe the activities that are performed to the information and data that is collected by FatiguePro before determining the cumulative fatigue usage for a component or an accrued transient cycle.

In its response dated May 3, 2012, the applicant stated that its Fatigue Monitoring Program is being upgraded under the CAP to use monitoring software that analyzes fatigue using all six stress components for locations that use stress-based fatigue monitoring and that this upgrade will include consideration of RIS 2011-14. The applicant explained that its procedures specify that the basis for engineering judgment must be documented in the body of the calculation and confirmed that its program does not perform NB-3600 analysis.

The staff finds it appropriate that the applicant reviewed the concerns discussed in RIS 2011-14 for applicability to its site and entered it into its corrective actions program for evaluation and resolution. In addition, the staff finds it appropriate that no immediate actions were needed because the applicant's procedures require the basis for engineering judgment to be documented, consistent with the principles defined in the "design control" and "quality assurance records" elements of Appendix B to 10 CFR Part 50.

The staff finds the applicant's response to RAI B.1.19-5 acceptable because the applicant's program was capable of (1) identifying and evaluating generic operating experience as possibly being applicable to its site, (2) ensuring that no immediate actions were needed in response to this RIS, as described above, and (3) determining that long-term actions were needed to upgrade its fatigue monitoring software. The staff's concern identified in RAI B.1.19-5 is resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs B.1.19-2 and B.1.19-5, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.19 provides the UFSAR supplement for the Fatigue 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 include a description of the monitoring methods used to manage fatigue. 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 April 4, 2012, the staff issued RAI B.1.19-1 requesting, in part, that the applicant include a description of the monitoring methods that the Fatigue Monitoring Program will use to manage cumulative fatigue damage.

In its response dated May 3, 2012, the applicant amended LRA Section A.1.19 to include a summary description of the monitoring methods it will use to manage cumulative fatigue damage during the period of extended operation. Specifically, the applicant included a description of how cycle counting, cycle-based fatigue monitoring and stress-based fatigue monitoring will be used to manage fatigue during the period of extended operation. The staff finds the applicant's response acceptable because the applicant included a summary description that describes the three monitoring methods and how they will be used to manage fatigue. Therefore, the UFSAR supplement for the Fatigue Monitoring Program is consistent with the corresponding program description in SRP-LR Table 3.0-1 and describes how its program will manage metal fatigue, including EAF, during the period of extended operation. This portion of the staff's concern described in RAI B.1.19-1 is resolved.

The staff also noted that LRA Section A.1.19 includes the enhancements described above to make the applicant's program consistent with GALL Report AMP X.M1 and make the program capable of managing fatigue before the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended by letter dated May 3, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Fatigue Monitoring Program, the staff determines that those 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. Also, the staff reviewed the enhancements and confirmed that their implementation before the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.19 Fire Protection

Summary of Technical Information in the Application. LRA Section B.1.20 describes the existing Fire Protection Program as consistent, with enhancements, with GALL Report AMP XI.M26, "Fire Protection." The LRA states that the program manages cracking, loss of material, and change in material properties for components with a fire barrier intended function through the use of visual inspections. The LRA also states that the program manages loss of material for the halon and CO_2 fire suppression systems using visual inspections and testing.

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.M26. 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 of GALL Report AMP XI.M26, "Fire Protection," states that the program includes visual inspections of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire resistant materials that perform a fire barrier function. During its audit of the applicant's Fire Protection Program, the staff noted that the applicant has fire barriers constructed of the materials Thermo-lag and 3M Interam. These materials are included in the fire barrier inspection procedures, but the LRA does not include aging management results for any components constructed of the materials Thermo-lag or 3M Interam. It is unclear to the staff why the Thermo-Lag and 3M Interam fire barrier materials are not included in the LRA given that the materials are used at the plant and are included in the plant's inspection procedures. By letter dated April 17, 2012, the staff submitted RAI B.1.20-1 requesting that the applicant state why there are no fire barriers constructed of Thermo-Lag and 3M Interam being managed for aging in the LRA, or revise the LRA to include aging management of these materials.

In its response dated May 15, 2012, the applicant stated that Thermo-lag and 3M Interam are materials used in fire wraps at the site and were included in the AMR item for fire wraps in LRA Table 3.5.2-4. The applicant revised the LRA to add Thermo-lag and 3M Interam to the material column of the fire wrap AMR item in LRA Table 3.5.2-4 and to the materials section of LRA Section 3.5.2.1.4. The staff finds the applicant's response acceptable because the applicant has revised the LRA to include aging management of Thermo-lag and 3M Interam fire wraps. The staff's concern described in RAI B.1.20-1 is resolved.

The "scope of program" program element of GALL Report AMP XI.M26, "Fire Protection," states that the program manages aging effects for the halon and CO_2 fire suppression systems. GALL Report AMP XI.M26 relies on visual inspections and functional tests to manage aging for halon and CO_2 fire suppression system components. During its audit of the applicant's Fire Protection Program, the staff noted that the applicant's CO_2 fire suppression system includes an outdoor CO_2 tank and that the exterior surface of the tank is not readily accessible for visual inspection, as it is covered with an outer steel housing and an intermediate insulation layer. However, based on the staff's review of LRA Table 3.3.2-13 and a search of all tanks contained in the LRA, it appears that there is no AMR item for this tank. It is unclear to the staff why the LRA does not include the outdoor CO_2 tank and how this tank will be managed for aging during the period of extended operation. By letter dated April 17, 2012, the staff submitted RAI B.1.20-2 requesting that the applicant: (a) justify why there is no AMR item for the outdoor CO_2 tank or include an AMR item for the tank; (b) if the tank sits directly on concrete or soil, state whether sealant or caulking is used at the external surface interface between the tank and concrete or earthen foundation, or state the basis for why sealant or caulking is not used; (c) if the tank sits directly on concrete or soil and the tank is not being managed for aging using the Aboveground Metallic Tanks Program, state the basis for why there is reasonable assurance that the tank will perform its current license basis functions throughout the period of extended operation; and (d) if the tank does not sit directly on concrete or soil, state the inspection methodology and frequency of inspections that will be used to manage aging given that the exterior surface of the tank is not readily accessible.

In its response dated May 15, 2012, the applicant stated for question (a) that the CO_2 tank is included in the AMR item for carbon steel tank exposed to air indoor uncontrolled in LRA Table 3.3.2-13. The applicant also stated that the environment is considered air indoor uncontrolled because the tank is inside an enclosure and is insulated. In its response to questions (b) and (c) the applicant stated that the tank is not in contact with concrete or soil. In its response to question (d) the applicant stated that the area around the tank inside the enclosure that is accessible will be monitored for moisture or rust stains emanating from the insulation using the Fire Protection Program to manage loss of material. The applicant revised the Fire Protection Program to include an enhancement to visually inspect the external surfaces of the CO_2 tank for signs of corrosion at least once every fuel cycle.

The staff reviewed the applicant's response to question (a) of RAI B.1.20-2 in the letter dated May 15, 2012, and noted that the GALL Report defines "air – indoor uncontrolled" as indoor air associated with systems whose temperatures are above the dew point such that condensation can occur, but only rarely. The GALL Report defines "air – outdoor" as outdoor air associated with components exposed to atmospheric air, ambient temperatures, humidity, and weather, including precipitation and wind. The CO_2 tank is located outdoors surrounded by insulation and a metal housing. The staff noted that the metal housing will protect the CO_2 tank from precipitation and wind, but the metal housing will not protect the CO_2 tank from humidity or the temperature extremes experienced outdoors. The staff noted that, for the carbon steel CO_2 tank, the inspection methods are the same regardless of whether the tank is exposed to indoor or outdoor air. However, that may not be true for components constructed of other materials. By letter dated July 17, 2012, the staff issued RAI B.1.20-2a requesting, in part, that the applicant state whether there are any other components in the LRA that are outdoors but have been evaluated as exposed to indoor air.

In its response dated August 13, 2012, the applicant stated that there are no other components in the LRA that are outdoors but were evaluated as exposed to indoor air. The staff finds this part of the applicant's response acceptable because there are no other outdoor items which have been evaluated as exposed to indoor air, and the CO_2 tank will be managed for exposure to humidity using the Fire Protection Program, as discussed below.

The staff reviewed the applicant's response to questions (b) and (c) of RAI B.1.20-2 in a letter dated May 15, 2012, and noted that use of sealants or caulking and the Aboveground Metallic Tanks Program is only applicable to tanks that sit on concrete or soil. The staff finds this part of the applicant's response acceptable because the CO_2 tank does not sit on concrete or soil.

The staff reviewed the applicant's response to question (d) of RAI B.1.20-2 in the letter dated May 15, 2012, and noted that during the staff's walkdown of the outdoor CO_2 tank, there did not appear to be any accessible portions of the tank or its foundation since the metal housing surrounding the tank covers the base of the tank and did not appear to have any access ports. The staff finds the applicant's response to question (d) unacceptable because it is unclear to the staff what portion of the tank will be made accessible for visual inspection or how an inspection for moisture or rust stains emanating from the tank is sufficient to detect loss of material from the tank before loss of intended function. By letter dated July 17, 2012, the staff issued RAI B.1.20-2a requesting, in part, that the applicant state what portion of the tank will be made accessible for visual inspection or how an inspection for moisture or rust stains emanating from the tank is sufficient to detect loss of material from the tank prior to loss of intended function.

In its response dated August 13, 2012, the applicant stated that the metal housing surrounding the CO_2 tank has a 3-foot diameter-bolted access cover which can be removed to perform the visual inspections. The applicant also stated that inspection techniques used for confined spaces, such as boroscopes and mirrors, will be used to examine a wide surface area of the tank. The applicant further stated that a bare metal inspection will be performed when the insulation is removed for maintenance, which is consistent with the guidance in GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." However, the staff noted that GALL Report AMP XI.M36 states that insulated surfaces may be inspected when the external surface is exposed (i.e., during maintenance) at such intervals that would ensure that the components' intended functions are maintained. The applicant's response did not address the frequency at which the bare metal inspections of the tank would be performed or the percentage of bare metal that would be exposed during the inspections. By letter dated September 14, 2012, the staff issued RAI B.1.20-2b requesting that the applicant state what portion of the CO_2 tank will be made accessible for bare metal inspection and the frequency or basis for the frequency at which bare metal inspections of the CO_2 tank will be performed.

In its response dated October 15, 2012, the applicant stated that the metal housing is a welded steel enclosure which is an integral part of the tank skid and access to the bare metal tank is only available through the access cover. Since only a small portion of the tank is accessible through the access cover, the applicant stated that tank level and pressure will be monitored daily during the period of extended operation, in addition to the visual inspection of the exterior surface of the tank through the access cover every refuel cycle. The applicant revised the program description and the UFSAR supplement to include monitoring tank level and pressure daily. The staff finds the applicant's response to RAI B.1.20-2b acceptable because monitoring tank level and pressure daily will ensure any breach in the tank integrity is quickly identified and visual inspections of the accessible portions of the tank every refuel cycle will ensure any degradation of the tank exterior is identified. The staff's concerns originally described in RAI B.1.20-2 are resolved.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" 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.1.20 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that the Fire Protection Program will be enhanced to require visual inspection of the halon and CO_2 fire suppression systems for signs of corrosion at least once every fuel cycle. The "detection of aging effects" program element of GALL Report AMP XI.M26 states that visual inspections of the halon and CO_2 fire suppression systems should be performed to identify signs of corrosion. During the audit the staff confirmed that the applicant's proposed frequency of once every fuel cycle is in accordance with its existing NRC-approved fire protection program as documented in its Technical Requirements Manual. 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 GALL Report recommendations by requiring visual inspections of the halon and CO_2 fire suppression systems.

Enhancement 2. LRA Section B.1.20 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to require visual inspection of fire damper framing at least once per refuel cycle for degradation. The "detection of aging effects" program element of GALL Report AMP XI.M26 states that visual inspections should be performed for fire barrier walls, ceiling, floors, doors, and other fire barrier materials on a frequency consistent with the applicant's NRC-approved fire protection program. During the audit the staff confirmed that the applicant's proposed frequency of once every fuel cycle is in accordance with its existing NRC-approved fire protection program as documented in its Technical Requirements Manual. 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 GALL Report recommendations by requiring visual inspections of fire barriers.

Enhancement 3. LRA Section B.1.20 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to require visual inspections of concrete curbs, manways, hatches, manhole covers, hatch covers, and roof slabs at least once every fuel cycle to confirm aging effects are not occurring. The "detection of aging effects" program element of GALL Report AMP XI.M26 states that visual inspections should be performed for fire barrier walls, ceiling, floors, doors, and other fire barrier materials on a frequency consistent with the applicant's NRC-approved fire protection program. During the audit, the staff confirmed that the applicant's proposed frequency of once every fuel cycle is in accordance with its existing NRC-approved fire protection program as documented in its Technical Requirements Manual. 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 GALL Report recommendations by requiring visual inspections of various types of fire barriers.

Enhancement 4. LRA Section B.1.20, as amended by letter dated May 15, 2012, states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that the Fire Protection Program will be enhanced to require an external visual inspection of the CO_2 tank at least once every fuel cycle. The "detection of aging effects" program element of GALL Report AMP XI.M26 states that visual inspections of the CO_2 fire suppression system should be performed to detect any signs of corrosion. As discussed in the "Staff Evaluation" section above, the CO_2 tank is mostly inaccessible for visual inspection because it is enclosed in a welded metal housing. Therefore, visual inspection of the accessible portions of the tank coupled with monitoring the level and pressure in the tank will be used to manage 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 ensure any degradation of the tank exterior is identified consistent with the GALL Report recommendations.

Summary. Based on its audit and review of the LRA and the applicant's responses to RAIs B.1.20-1, B.1.20-2, B.1.20-2a, and B.1.20-2b, the staff finds that the program elements for which the applicant claimed consistency with GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M26. In addition, the staff reviewed the enhancements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.20 summarizes operating experience related to the Fire Protection Program. The LRA states that inspections have identified small tears in fire doors, rust on fire doors, cracks in fire doors, missing pieces of fireproofing, and missing Kaowool in penetration seals. The LRA also states that these deficiencies were repaired. The LRA further states that audits and self-assessments have been conducted to identify recommendations to upgrade the program to ensure its effectiveness.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.20 provides the UFSAR supplement for the Fire Protection 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 LRA Section A.1.20 does not state that the program includes functional tests of fire-rated doors. 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 April 17, 2012, the staff issued RAI B.1.20-3 requesting that the applicant revise LRA Section A.1.20 to include functional tests of fire-rated doors.

In its response dated May 15, 2012, the applicant revised the UFSAR supplement to state that the program includes functional tests of fire-rated doors. The staff finds the applicant's response acceptable because the applicant has amended the UFSAR supplement to include functional tests of fire-rated doors. Therefore, the UFSAR supplement for the Fire Protection Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.1.20-3 is resolved.

The staff noted that the applicant committed (Commitment No. 11) to enhance the Fire Protection Program to require visual inspections at least once every fuel cycle of the halon and CO_2 fire suppression systems for signs of corrosion; fire damper framing for degradation; and concrete curbs, manways, hatches, manhole covers, hatch covers, roof slabs to confirm aging effects do not occur; and the external surfaces of the CO_2 tank for signs of corrosion.

The staff finds that the information in the UFSAR supplement, as amended by letter dated October 15, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's 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 through Commitment No. 11 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. 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 Fire Water System

Summary of Technical Information in the Application. As amended by letters dated May 15, 2012, June 27, 2012, August 13, 2012, May 13, 2014, November 6, 2014, May 20, 2015, August 19, 2015, and November 23, 2015, LRA Section B.1.21 describes the existing Fire Water System Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M27, "Fire Water System," as modified by LR-ISG-2012-02. The LRA states that the program manages loss of material, fouling, and loss of coating integrity for components in fire protection systems through the use of preventive, inspection, and monitoring activities, including flush tests and testing and replacement of sprinkler heads. The LRA also states that the system is maintained at required pressure and actions are taken upon a loss of system pressure.

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.M27. 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.

GALL Report AMP XI.M27 applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, fire pump casings, hydrants, hose stations, standpipes, water storage tanks, and aboveground, buried, and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Buried fire main piping and sprinkler heads exposed to both air and water are included within the scope of GALL Report AMP XI.M27. LRA Section 2.3.3.12 states that the applicant's fire water system includes both wet-pipe and dry-pipe sprinkler systems. However, there are no AMR items for sprinkler heads and no AMR items for copper-alloy components exposed to air for which aging effects are being managed using the Fire Water System Program. LRA Section 2.3.3.12 states that the underground yard loop is constructed of cement-lined cast iron piping. However, there are no AMR items in the LRA for cast iron or carbon steel piping exposed to cement or for cement-lined piping.

It is not clear to the staff whether the aging effects associated with the cement-lined cast iron yard loop and sprinkler heads will be managed using the Fire Water System Program. There are activities in the Fire Water System Program capable of managing aging effects for these components, but there are no AMR items that reference the Fire Water System Program. By letter dated April 17, 2012, the staff issued RAI B.1.21-2 requesting that the applicant list AMR items for the sprinkler heads and cement-lined cast iron yard loop as stated above.

In its response dated May 15, 2012, the applicant stated that no credit is taken for the concrete lining in the cast iron yard loop to prevent aging effects; therefore, the yard loop is listed as carbon steel piping in LRA Table 3.3.2-12. The staff finds the applicant's response acceptable because the buried fire main is being managed for aging of the internal surfaces using the Fire Water System Program consistent with the GALL Report recommendations. However, as amended by letter dated May 13, 2014, LRA Table 3.3.2-12 states that metallic piping with Service Level III or other internal coating exposed to raw water is managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of the use of the Periodic Surveillance and Preventive Maintenance Program to manage loss of coating integrity is documented in SER Section 3.0.3.3. The staff finds the use of this program to manage the internally coated surfaces of this fire protection piping acceptable because periodic visual examinations conducted in accordance with the Periodic Surveillance and Preventive Maintenance Program are capable of detecting loss of coating (inclusive of cement lining) integrity.

In its response dated May 15, 2012, the applicant also stated that sprinklers are listed as nozzles in LRA Table 3.3.2-12 and that they are managed by the Fire Water System and Selective Leaching Programs. However, the staff noted that the only entry for nozzles in LRA Table 3.3.2-12 that uses the Fire Water System Program to manage aging is the AMR item for nozzles exposed to raw water. The AMR items for nozzles exposed to indoor air state that the components have no AMR. As stated in RAI B.1.21-2, sprinkler heads exposed to both air and water are included within the scope of GALL Report AMP XI.M27. It is unclear to the staff why aging effects associated with the nozzles exposed to air do not require aging management. By letter dated July 17, 2012, the staff issued follow-up RAI B.1.21-2a requesting that the applicant state the basis for why the nozzles exposed to indoor air do not require aging management.

In its response dated August 13, 2012, the applicant stated that the nozzles exposed to indoor air have no aging effects identified, consistent with GALL Report item VII.J.AP-144. However, the applicant also stated that aging effects associated with all sprinkler heads within the scope of license renewal will be managed by the Fire Water System Program, regardless of whether aging effects are identified. The staff finds the applicant's response acceptable because all sprinkler heads within the scope of license renewal will be replaced or tested consistent with the recommendations in GALL Report AMP XI.M27. The staff's concerns described in RAIs B.1.21-2 and B.1.21-2a are resolved.

Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02, which revised several AMPs, including the guidance for AMP XI.M27, “Fire Water System.” By letter dated January 2, 2014, the staff issued RAI 3.0.3-1 requesting that the applicant provide details on how the updated guidance of LR-ISG-2012-02 has been accounted for in the LRA AMPs, or provide adequate justification for why incorporation is not required.

In its responses dated May 13, 2014; November 6, 2014; May 20, 2015; August 19, 2015; and November 23, 2015, the applicant modified existing enhancements and added exceptions.

The staff reviewed the portions of the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements associated with the exceptions and 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 exceptions and enhancements follows.

Exception 1. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an exception to the “detection of aging effects” program element. In this exception the applicant stated that it will perform sprinkler inspections on a 24-month interval in lieu of annual testing required by NFPA 25, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” Section 5.2.1. The applicant also stated that the 24-month inspection interval has been effective at maintaining component-intended function. The staff noted that NFPA 25 was written for a broad range of facilities, including those with a few sprinklers (e.g., a small manufacturing facility with only a dozen sprinklers) and those with numerous sprinklers (as is typical for power plants). The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because the applicant stated that the 24-month inspection interval has not resulted in a loss of intended functions in the past, the staff’s independent search of plant-specific operating experience during the audit did not reveal any evidence that sprinkler degradation was occurring, and a sufficient number of sprinklers are installed in commercial nuclear power plants to establish an adverse performance trend, even with plant-specific inspections being completed on a 24-month basis rather than annually.

Exception 2. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an exception to the “detection of aging effects” program element. In this exception, the applicant stated that sprinklers will not be inspected for orientation, foreign material, physical damage, and loading due to dust or debris, as required by NFPA 25 Section 5.2.1.1. The staff noted that LR-ISG-2012-02 AMP XI.M27 Table 4a, “Fire Water System Inspection and Testing Recommendations,” footnote 1, states that: “[t]his table specifies those inspections and tests that are related to age-managing applicable aging effects associated with loss of material and flow blockage for passive long-lived, in-scope components in the fire water system.” The staff also noted that Enhancement No. 6 states that the Fire Water System procedures will be enhanced to include inspections of sprinklers in the overhead from the floor. The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because sprinkler inspections will be conducted to detect corrosion, this being the age-related aging effect identified in NFPA 25 Section 5.2.1.1.1, and inspecting sprinklers from the floor is consistent with NFPA 25 and therefore, LR-ISG-2012-02 AMP XI.M27.

Exception 3. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an exception to the “detection of aging effects” program element. In this exception, the applicant stated that it will not perform flow testing at the hydraulically most remote hose connections of each zone of an automatic standpipe system to verify that the water supply provides the design pressure, as required by NFPA 25 Section 6.3.1. The applicant also stated that it alternatively: (a) performs main header flow testing every 3 years (reference response to RAI 3.0.3-1-FWS-1 dated November 6, 2014) in seven loops that supply the standpipe system to verify that the water supply provides the design pressure and required flow, (b) tests the fire water hose stations, including approximately 43 fire water hose stations in the auxiliary building, 16 in the containment building, 2 in the emergency diesel generator (EDG) building, and 13 in the control building every 3 years to ensure that there is no blockage, and (c) performs an annual "version" of a main drain test in each building on a portion of the deluge and sprinkler systems. The applicant further stated that the acceptance criteria used to verify an open flow path includes verifying flow through the valve and connection and that there are no indications of obstruction or other undue restriction of water flow. The applicant stated that NFPA 25 (2014 Edition), Section 6.3.1, has been revised to state that the testing is only applicable to Class I and Class III standpipe systems and its automatic standpipe system is Class II.

The staff noted the following:

- NFPA 25, Section 6.3.1, requires that flow testing be conducted every 5 years.
- The purpose of flow tests is to detect potential flow blockage.
- Exception No. 4 states that 30 main drain tests are conducted, encompassing testing in the auxiliary building, turbine building, control building, and EDG building.
- A Class II standpipe system is differentiated from Class I and Class III systems, based on the size of the hose stations supplied by the standpipe and its use (e.g., a Class I or Class III system supplies a larger volume of water for use by fire departments).

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because the proposed alternative testing is sufficient to establish reasonable assurance that flow blockage will be detected prior to a CLB intended function not being met. The staff based this conclusion on: (a) the alternative flow tests, both in number, breadth of locations, and frequency, provide insights concerning the potential accumulation of corrosion products that are comparable to those gained from the test recommended in LR-ISG-2012-02 AMP XI.M27, (b) in regard to the number of tests, main header flow testing is conducted every 3 years, 74 hose stations are tested every 3 years to verify no flow blockage, and multiple main drain tests are conducted on an annual basis, (c) in regard to the breadth of testing, the testing will encompass piping located in five different buildings, (d) in regard to the frequency of testing, the alternative tests are conducted more frequently than every 5 years, and (e) NFPA 25 (2014 Edition), an industry consensus document, has removed the requirement to conduct the test for the class of standpipe used at the station.

Exception 4. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that it does not perform main drain tests on all standpipes and risers as required by NFPA 25 Sections 6.3.1.5 and 13.2.5. The applicant stated that it performs more than 30 main drain tests throughout the plant associated with in-scope standpipes and risers, for example 6 in the auxiliary building, 10 in the turbine building, 2 in the control building, and 3 in the EDG building. The applicant also stated that the turbine building risers only have an intended function, as described in 10 CFR 54.4(a)(2).

The staff noted the following:

- LR-ISG-2012-02 AMP XI.M38, “Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components,” provides insights related to an acceptable inspection sampling methodology to manage aging of components, materials, and environments comparable to that in fire water systems. LR-ISG-2012-02 AMP XI.M38 is a program based on opportunistic inspections with a recommended inspection of either 20 percent or a maximum of 25 components of each material, environment, and aging effect combination in each 10-year period of the period of extended operation.
- NFPA 25 (2014 Edition), Sections 13.2.5 and 13.2.5.1, allows a reduced number of main drain tests to be conducted. It states: “[a] main drain test shall be conducted annually for each water supply lead-in to a building water-based fire protection system to determine whether there has been a change in the condition of the water supply. Where the lead-in to a building supplies a header or manifold serving multiple systems, a single main drain test shall be permitted.”

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable, in part, because, although the applicant has not proposed to conduct main drain tests in each water-based fire protection system riser, the proposed alternative testing is sufficient to establish reasonable assurance that flow blockage will be detected prior to a current licensing basis intended function not being met. The staff based this conclusion on the following: (a) the main drain tests, both in number and scope of locations, provide insights concerning the potential accumulation of corrosion products that are sufficient from a sampling basis, (b) in regard to the number of tests, the applicant has proposed to periodically perform 30 main drain tests, which exceeds the maximum of 25 inspections cited in random sampling programs recommended in GALL Report AMPs XI.M32, XI.M33, and XI.M38, (c) in regard to the scope of locations, the testing will encompass piping located in four different buildings, and (d) given the intended function of risers in the turbine building, flow blockage is not an applicable aging effect and, therefore, main drain tests need not be conducted for license renewal purposes. However, given the use of the term “version” (associated with main drain tests in Exception No. 3), it is not clear to the staff how main drain tests are conducted and, as a result, whether the tests have the capability to detect potential flow blockage. In addition, Exception No. 4 did not state the periodicity of conducting the 30 main drain tests and header flow testing. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-FWS-1 requesting that the applicant state: (a) how main drain tests are conducted in comparison to NFPA 25 (2011 Edition) Sections 6.3.1.5 and 13.2.5, and (b) the periodicity of conducting the 30 main drain tests and header flow testing.

In its response dated November 6, 2014, the applicant stated that the main drain tests are conducted consistent with Section 13.2.5 of NFPA 25, 2011 Edition. The applicant described how the tests are conducted (i.e., test location, parameter monitored, test method). The applicant stated that a flow blockage evaluation is conducted if “the flowing pressure drops more than 10 percent from the previous test in the same location.” The applicant also stated that main drain tests are conducted annually and header flow testing is conducted every 3 years.

The staff finds the applicant’s response acceptable, in part, because, based on the staff’s review of the applicant’s main drain testing details, the test location, parameter monitored, test method, and frequency of testing are consistent with NFPA 25 Section 13.2.5. In addition, header flow testing is conducted more frequently than required by NFPA 25 Section 6.3.1, every 3 years versus every 5 years. However, the applicant’s acceptance criteria are not consistent with NFPA 25 Section 13.2.5, which states that the 10-percent reduction in full flow pressure should be compared to the original acceptance test or previously performed tests, not only the "previous test." By comparing the result of the main drain test to only the previous test, decreases in full flow pressure (indicative of potential flow blockage) could accumulate over time and exceed a 10-percent reduction in flow. By letter dated April 6, 2015, the staff issued RAI 3.0.3-1-FWS-1a, requesting that the applicant state the basis for how comparing the current test result to only the previous test result will be effective in determining whether potential flow blockage is occurring and how effective trending can be accomplished.

In its response dated May 20, 2015, the applicant revised LRA Section A.1.21, Enhancement No. 18, and Commitment No. 12, to state, "[r]evise Fire Water System procedures to perform a flow blockage evaluation if, during main drain testing, the flowing pressure drops more than 10 percent from the flowing pressure observed during the original acceptance test or other previously performed tests at the same location."

The staff finds the applicant's response acceptable because the revised exception is consistent with LR-ISG-2012-02 AMP XI.M27 and NFPA 25 Section 13.2.5, which can ensure that an adequate number of data points are reviewed in order to determine a trend in performance. The staff's concern described in RAIs 3.0.3-1-FWS-1 and 3.0.3-1-FWS-1a is resolved. The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable, based on the above staff finding statements.

Exception 5. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that the calibration of gauges (NFPA 25 Section 6.3.1.5.2) is part of ongoing operations and is not part of the Fire Water System Program. The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because the calibration of test equipment is not addressed in LR-ISG-2012-02 AMP XI.M27 and the staff recognizes that the calibration of gauges is controlled by plant-specific procedures.

Exception 6. As amended by letter dated August 19, 2015, LRA Section B.1.21 states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that, in relation to testing in accordance with NFPA 25 Section 9.2.7 (1), "[a]lternate adhesion tests endorsed in Reg Guide 1.54 may apply." The applicant also stated that, "[a]lternative adhesion testing endorsed by Reg. Guide 1.54 will be applied as alternative testing when required." The applicant stated that when indications of coating degradation are identified in the fire water tank coating, the applicant performs holiday testing. In addition, GGNS performs ultrasonic thickness checks or mechanical measurements of any corroded areas.

The staff noted that NFPA 25 Sections 9.2.6.4 and 9.2.7.1 require adhesion testing when steel tanks exhibit signs of interior pitting, corrosion, or failure of coating. RAI 3.0.3-1-FWS-2 part (b) and RAI 3.0.3-1-FWS-2a (issued by letter dated April 6, 2015) became not applicable, based on the revisions to Exception No. 6 and Enhancement Nos. 9 and 23, and the addition of Enhancement No. 26, as described in the letter dated August 19, 2015. These two RAIs requested that the applicant state what alternatives it would use in regard to adhesion testing. The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," and finds it acceptable, because RG 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," includes staff-endorsed standards for conducting adhesion testing, in addition to the method cited in NFPA 25 Section 9.2.7 (1).

Exception 7. As amended by letter dated November 6, 2014, Exception No. 7, originally cited in the letter dated May 13, 2014, was deleted. The exception had stated that the deluge valves associated with the charcoal filters, turbine building hydrogen seal oil reservoir, and recirculation feed pump turbine (RFPT) lube oil reservoir are not full flow tested as required by NFPA 25 Section 13.4.3.2.2. The applicant stated that the turbine building hydrogen seal oil and RFPT lube oil reservoir deluge valves only have an intended function as described in 10 CFR 54.4(a)(2). The applicant further stated that the deluge systems associated with the auxiliary building standby containment cooling system and containment vent charcoal filters are not trip tested due to the potential for water damaging the charcoal in the filter units. The applicant stated that the piping downstream of manual deluge trip valves is dry and the deluge nozzles are within the filter housing and not easily accessible. The applicant also stated that the nozzles are inspected when charcoal is replaced (Enhancement No. 10).

The staff noted that NFPA Section 13.4.3.2.2.5(A) states: "[w]here the nature of the protected property is such that water cannot be discharged, the nozzles or open sprinklers shall be inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed."

The staff concluded that, given the intended function of the turbine building hydrogen seal oil and RFPT lube oil reservoir deluge valves, flow blockage is not an applicable aging effect and therefore deluge valve testing need not be conducted for license renewal purposes. However, given that deluge valve flow testing can be conducted using air, it was not clear why full flow testing of deluge valves in the remaining systems cannot be conducted in accordance with NFPA 25. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-FWS-3 requesting that the applicant state the basis for why: (a) full flow testing of deluge valves cannot be conducted in accordance with NFPA 25, and (b) there is reasonable assurance that flow blockage will be detected when full flow deluge valve testing is not conducted.

In its response dated November 6, 2014, the applicant deleted Exception No. 7 and revised its Fire Water System program to include Enhancement No. 19. This enhancement states that air flow testing will be conducted to detect flow obstructions downstream of the deluge valves for the control room fresh air, auxiliary building standby gas, containment cooling system, and containment vent charcoal filter units on a refueling cycle interval.

The staff finds the applicant's response and deletion of Exception No. 7 acceptable because conducting air flow testing in order to demonstrate the absence of flow blockage downstream of deluge valves is an acceptable method as cited in NFPA 25. The staff's concern described in RAI 3.0.3-1-FWS-3 is resolved.

Enhancement 1. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that the program will be enhanced to include periodic visual inspection of spray and sprinkler system internals for degradation. The staff noted that the wording, "[a]cceptance criteria will be enhanced to verify no unacceptable degradation," was deleted in this amendment; however, it was replaced by Enhancement No. 13. The staff's evaluation of this change is documented below. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include internal visual inspections of spray and sprinkler system piping consistent with LR-ISG-2012-02 AMP XI.M27 recommendations.

Enhancement 2. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that it will enhance the program to include periodic inspection of hose reels for degradation. GALL Report AMP XI.M27 recommends that water-based fire protection system components, including hose stations, be tested to ensure minimum functionality of the system is maintained. In its response to RAI 3.5.2.4-4, dated July 27, 2012, which is documented in SER Section 3.5.2.1.4, the applicant stated that the hose stations will be inspected annually. An annual hose station inspection frequency is consistent with the recommendations in NFPA 25 and further clarifies the periodic inspection frequency this enhancement describes. 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 enhance the program to include inspection of hose reels to ensure minimum functionality is maintained, consistent with the GALL Report recommendations. The staff noted that the wording, “[a]cceptance criteria will be enhanced to verify no unacceptable degradation,” was deleted in this amendment. The staff finds this acceptable because the “acceptance criteria” program element in LR-ISG-2012-02 AMP XI.M27 does not include any recommendations related to acceptance criteria for hose reel inspections and therefore it is acceptable to use plant-specific inspection acceptance criteria.

Enhancement 3. LRA Section B.1.21 stated an enhancement to the “detection of aging effects” program element; however, as amended by letter dated May 13, 2014, this enhancement was deleted. In this enhancement, the applicant had stated that the program will be enhanced to include either wall thickness evaluations using nonintrusive techniques or visual inspections of the internal surfaces of fire protection piping upon each entry to the system for routine or corrective maintenance. The staff finds the deletion of this enhancement acceptable because LR-ISG-2012-02 AMP 27 does not recommend the use of wall thickness evaluations in lieu of internal inspections and the Fire Water System Program has been amended to be consistent, with exception, to LR-ISG-2012-02 AMP XI.M27. The staff noted that the responses to RAI B.1.21-3 and RAI B.1.21-3a, dated May 15, 2012, and August 13, 2013, respectively, are no longer applicable as they were related to the periodic performance of visual inspections based on GALL Report AMP XI.M27 and not LR-ISG-2012-02 AMP XI.M27.

Enhancement 4. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the program will be enhanced to include visual inspection of the interior surface of below grade fire protection piping for a representative number of locations at least once every 10 years during the period of extended operation. A representative sample will be 20 percent of each population having the same material, environment, and aging effect combination, with a maximum of 25 inspections.

It was unclear to the staff whether flow testing will be conducted in addition to visual inspections to manage aging for the below grade fire protection piping. If only visual inspections will be performed, it is unclear to the staff whether the 10-year inspection frequency will be adequate. By letter dated April 17, 2012, the staff issued RAI B.1.21-4 requesting that the applicant clarify whether flow testing and visual inspections will be used to manage aging for the below grade fire protection piping; and, if only visual inspections will be performed, state the basis for the frequency of inspections, including any past inspection results that support the chosen inspection frequency.

In its response dated May 15, 2012, the applicant stated that both flow testing and visual inspections will be used to manage aging for the below grade fire protection piping. The applicant stated that flow testing is performed every 3 years and includes below ground piping. The staff finds the applicant's response acceptable because flow testing will be performed every 3 years and visual inspections will be performed every 10 years to manage aging for the internal surfaces of below ground fire protection piping. The staff's concern described in RAI B.1.21-4 is resolved.

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 enhance the program to include visual inspections of the internal surfaces of below grade piping at a sufficient frequency on a reasonable number of locations, consistent with the GALL Report recommendations. The staff noted that the wording, "[a]cceptance criteria will be enhanced to verify no unacceptable degradation," was deleted in this amendment; however, it was replaced by Enhancement No. 13. The staff's evaluation of this change is documented below.

Enhancement 5. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to ensure that sprinkler heads will be tested or replaced in accordance with NFPA 25 Section 5.3.1. LR-ISG-2012-02 AMP XI.M27 recommends that sprinklers that have been in place for 50 years be replaced or a representative sample of sprinklers be tested in accordance with NFPA 25. The staff noted that, based on the changes in the May 13, 2014, letter, the response to RAI B.1.21-5, dated May 15, 2012, is no longer applicable. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include replacement or testing of sprinkler heads consistent with LR-ISG-2012-02 AMP XI.M27 recommendations.

Enhancement 6. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to include inspecting sprinklers in the overhead from the floor for signs of corrosion. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, sprinkler inspections will be consistent with LR-ISG-2012-02 AMP XI.M27 recommendations and NFPA 25 Section 5.2.1.1.

Enhancement 7. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to replace sprinklers that the tested sprinklers represented if the tested sprinkler fails its test. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, sprinkler inspections will be consistent with LR-ISG-2012-02 AMP XI.M27 recommendations and NFPA 25 Section 5.3.1.3.

Enhancement 8. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to ensure that, during flushing, hydrant valves will be opened fully and ensure that the hydrant flows for not less than 1 minute during flow testing. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, hydrant flushing will be consistent with LR-ISG-2012-02 AMP XI.M27 recommendations and NFPA 25 Sections 7.3.2.1 and 7.3.2.2.

Enhancement 9. As amended by letter dated August 19, 2015, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant described changes to the fire water system procedures related to tests and inspections of the internal surfaces of fire tanks required by NFPA 25 Section 9.2.7. The staff noted that the list of tests and inspections includes all those required by NFPA 25 Sections 9.2.6 and 9.2.7; except vacuum box testing. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-FWS-2 requesting that the applicant state whether vacuum box testing will be conducted.

In its response dated November 6, 2014, the applicant stated that the fire water tanks have domed bottoms and NFPA 25 Section 9.2.7 only requires vacuum box testing on flat bottom tanks.

The staff finds the applicant's response acceptable because it is consistent with NFPA 25, in that the configuration of the tank bottom is not within the scope of Section 9.2.7 (6). The staff's concern described in RAI 3.0.3-1-FWS-2 is resolved.

In addition, the staff noted that the applicant cited adhesion tests endorsed by RG 1.54 in lieu of the adhesion methodology cited in NFPA 25 Section 9.2.7 (1). The staff's evaluation of adhesion testing associated with this enhancement is documented in Exception No. 6. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and LR-ISG-2013-01 and finds it acceptable because, when it is implemented, it will enhance the program to include inspections and tests of fire water tank internals consistent with LR-ISG-2012-02 AMP XI.M27 recommendations.

Enhancement 10. As amended by letter dated August 19, 2015, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to ensure that there is no flow blockage of charcoal filter fire water distribution piping by conducting visual inspections when the charcoal is replaced. However, the staff noted that the enhancement was revised to state that the charcoal filter deluge piping in lieu of the nozzles would be inspected for flow blockage. No basis was provided for inspecting the fire water distribution piping in lieu of nozzles. By letter dated October 29, 2015, the staff issued RAI 3.0.3-1-FWS-9 requesting that the applicant state the basis for why the fire water distribution piping for the charcoal deluge system will be inspected instead of nozzles.

In its response dated November 23, 2015, the applicant stated that, "[i]t was determined that the phrase "fire water distribution piping" within the charcoal filter units was more appropriate than "nozzles" based on vendor manual wording."

The staff finds the applicant's response acceptable because the plant-specific configuration for the distribution piping includes fire water distribution components. The staff's concern described in RAI 3.0.3-1-FWS-9 is resolved. The staff's evaluation of the adequacy of tests and inspections associated with deluge valves is documented in Exception No. 7. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include charcoal filter deluge testing and inspections consistent with LR-ISG-2012-02 AMP XI.M27 recommendations.

Enhancement 11. As amended by letter dated August 19, 2015, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that, for preaction and dry pipe systems, the fire water system procedures will be revised to periodically open a flushing connection and remove a component toward the end of one branch line to perform a visual inspection in accordance with NFPA 25 Section 14.2.1. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, conducting internal inspections of preaction and dry pipe systems in accordance with NFPA 25 Section 14.2.1, as well as the augmented inspections described in Enhancement No. 21, can be sufficient to detect potential flow blockage.

<u>Enhancement 12</u>. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to inspect the strainers upstream of the deluge valves every 3 years. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include deluge valve strainer inspections consistent with LR-ISG-2012-02 AMP XI.M27 recommendations and NFPA 25 Section 10.2.1.7.

<u>Enhancement 13</u>. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to state an acceptance criterion that, during flow testing, main drain testing, and internal inspections, no corrosion products sufficient to obstruct flow or clog downstream components are permitted. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, along with Enhancement No. 15, it will enhance the program to include acceptance criteria consistent with the "acceptance criteria" program element of LR-ISG-2012-02 AMP XI.M27.

<u>Enhancement 14</u>. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to state that any sprinkler that exhibits signs of leakage or corrosion will be replaced. The staff reviewed this enhancement against the "detection of aging effects" program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include replacement criteria for degraded sprinklers consistent with LR-ISG-2012-02 AMP XI.M27 recommendations and NFPA 25 Section 5.2.1.1.2.

<u>Enhancement 15</u>. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to:

> require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the Corrective Action Program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains and branch lines, and the performance of a complete flushing program by qualified personnel.

The staff reviewed this enhancement against the "detection of aging effects" and "acceptance criteria" program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include appropriate actions when corrosion or blockages are identified during tests and inspections consistent with the LR-ISG-2012-02 AMP XI.M27 recommendations and NFPA 25 Section 14.2.1.3.

Enhancement 16. As amended by letter dated May 13, 2014, LRA Section B.1.21 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to: "require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access." The staff reviewed this enhancement against the "detection of aging effects" program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, it will enhance the program to include a follow-up obstruction investigation in accordance with NFPA 25 Section 14.3.1, item (9).

Enhancement 17. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the "parameters monitored/inspected" and "detection of aging effects" program elements to address RAI 3.0.3-1-FWS-5. The staff noted that the "parameters monitored/inspected" and "detection of aging effects" program elements of LR-ISG-2012-02 AMP XI.M27 state that, when visual inspections are used to detect loss of material, the inspection technique should be capable of detecting surface irregularities that could indicate wall loss to below nominal pipe wall thickness due to corrosion and corrosion product deposition and, where such irregularities are detected, follow-up volumetric wall thickness examinations are performed. The staff also noted that there were no exceptions or enhancements associated with this recommendation. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-FWS-5 requesting that the applicant state how this recommendation has been incorporated into the Fire Water System program or provide justification for why incorporation is not required.

In its response dated November 6, 2014, the applicant enhanced its program to require follow-up volumetric wall thickness examinations when visual inspections detect, "excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer."

The staff finds the applicant's response and enhancement acceptable because volumetric wall thickness examinations will be conducted when surface irregularities indicative of wall loss are detected. The staff's concern described in RAI 3.0.3-1-FWS-5 is resolved.

Enhancement 18. As amended by letter dated November 6, 2014; and May 20, 2015, the applicant stated an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to "perform a flow blockage evaluation if during main drain testing, the flowing pressure drops more than 10 percent from the flowing pressure observed during the original acceptance test or other previously performed tests at the same location." The staff's evaluation of this enhancement is documented above in Exception No. 4.

Enhancement 19. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to "perform air flow testing to ensure there are no obstructions downstream of the deluge valves for control room fresh air, auxiliary building standby gas, containment cooling system, and containment vent charcoal filter units each refueling cycle." The staff's evaluation of this enhancement is documented above in Exception No. 7.

Enhancement 20. As amended by letter dated November 6, 2014, LRA Section B.1.21 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated the following:

> Revise Fire Water System Program procedures to require internal inspections at the end of one fire main and the end of one branch line on two of the wet pipe systems in the auxiliary building, two of the wet pipe systems in the control building, and one wet pipe system in the fire pump house every five years. During each five-year period, inspect different wet pipe sprinklers such that internal inspections are performed on all of the wet pipe sprinkler systems in the auxiliary and control buildings every 15 years and in the fire pump house every 10 years. In the event internal obstructions are identified in a building wet pipe system, expand the number of inspections to include all of the wet pipe sprinkler systems in that building.

The staff noted that NFPA 25 Section 14.2.2 requires, on an alternating schedule, an internal inspection of every other wet-pipe system in buildings with multiple wet-pipe systems. The staff lacked sufficient information to complete its evaluation of the applicant's proposal because it was not clear whether there are multiple wet-pipe systems in any of the structures containing in-scope fire water systems. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-FWS-4 requesting that the applicant state the basis for why testing is not conducted on every other system every 5 years.

In its response dated November 6, 2014, the applicant stated that: (a) the in-scope wet-pipe sprinkler systems in the auxiliary building, control building, and fire pump house are fabricated from the same material, and exposed to the same environment and (b) the auxiliary building has six in-scope wet-pipe sprinkler systems, the control building has five, and the fire pump house has two.

Although the applicant will be inspecting five wet-pipe systems in lieu of seven locations, as cited by NFPA 25, the staff finds the applicant's response and Enhancement No. 20 acceptable because: (a) given that the wet systems are constructed of the same materials and exposed to the same environment, there is reasonable assurance that flow blockage occurring in any one of the systems would be indicative of the same conditions in the other systems, (b) if the applicant detects obstructions in any system within a building, it will inspect the other systems in that building, and (c) in each 5-year period, the applicant will inspect at least one system in each of the buildings with in-scope wet-pipe systems. The staff's concern described in RAI 3.0.3-1-FWS-4 is resolved.

Enhancement 21. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the "detection of aging effects" program element to address RAI 3.0.3-1-FWS-6. The staff noted that the "parameters monitored/inspected" and "detection of aging effects" program elements of LR-ISG-2012-02 AMP XI.M27 state that periodic visual inspections or flow tests and volumetric inspections should be conducted on portions of water-based fire protection system components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves. The staff also noted that there are no exceptions or enhancements associated with this recommendation. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-FWS-6 requesting that the applicant state how this recommendation has been incorporated into the Fire Water System program or provide justification for why incorporation is not required.

In its response dated November 6, 2014, the applicant enhanced the program to conduct periodic visual inspections or flow tests and volumetric inspections on portions of water-based fire protection system components that have been wetted but are normally dry. The enhancement incorporates all of the recommended tests and inspections and the corresponding test parameters, extent of tests and inspections, and periodicity of testing.

The staff finds the applicant's response and Enhancement No. 21 acceptable because it is consistent with AMP XI.M27 as modified by LR-ISG-2012-02, which ensures that sufficient tests or inspections of normally dry but periodically wetted portions of the fire water system that collect water will be conducted in order to detect flow blockage. The staff's concern described in RAI 3.0.3-1-FWS-6 is resolved.

Enhancement 22. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to include requirements associated with the review of prior coating inspection results prior to the conduct of coating inspections and the information to be included in coating inspection reports. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2013-01 and finds it acceptable because, when it is implemented, it will enhance the program to include monitoring and trending requirements consistent with LR-ISG-2013-01, which ensures that adequate information in relation to coating degradation is provided for future inspections.

Enhancement 23. As amended by letter dated August 19, 2015, LRA Section B.1.21 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant described changes to the fire water system procedures related to tests and inspections of the internal surfaces of fire tanks required by NFPA 25 Section 9.2.7. The staff's evaluation of these same enhancements to the "detection of aging effects" program element is documented in Enhancement No. 9.

Enhancement 24. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the "acceptance criteria" program element. This enhancement was revised by letter dated May 20, 2015, and subsequently revised by letter dated August 19, 2015; however, the August 19, 2015, letter revised the November 6, 2014, version of this enhancement, not the May 20, 2015, version. By letter dated October 29, 2015, the staff issued RAI 3.0.3-1-FWS-10 requesting that the applicant revise the enhancement to reflect the correct version of the proposed changes to the Fire Water System Program.

In its response dated November 23, 2015, the applicant revised this amendment to reflect the changes in the May 20, 2015, and August 19, 2015, letters.

The staff finds the applicant's response acceptable because the revised version of Enhancement No. 24 reflects the changes in the May 20, 2015, and August 19, 2015, letters. The evaluation of this enhancement follows. The staff's concern described in RAI 3.0.3-1-FWS-10 is resolved.

In this enhancement, the applicant stated that the fire water system procedures will be revised to include acceptance criteria when coating defects are identified, including, "(1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to a few intact small blisters that are completely surrounded by sound coating bonded to the surface." The staff noted that the applicant did not state acceptance criteria for flaking, rusting, wall thickness measurements, and adhesion test results. In addition, the acceptance criteria did not include any details on the acceptable size of blisters or for changes in size or frequency of occurrence. By letter dated April 6, 2015, the staff issued RAI 3.0.3-1-FWS-8 requesting that the applicant state the acceptance criteria for flaking, rusting, wall thickness measurements, adhesion test results, size of blisters, and changes in the size or frequency of occurrence of blisters.

In its response dated May 20, 2015, as amended by letter dated November 23, 2015, the applicant revised this enhancement, LRA Section A.1.21, and Commitment No. 12, to state the same acceptance criteria as stated in the "acceptance criteria" program element of LR-ISG-2013-01, AMP XI.M42.

The staff finds the applicant's response and this enhancement acceptable because the acceptance criteria are consistent with those stated in LR-ISG-2013-01, which can ensure that degraded coatings requiring repair, replacement, or removal are identified. The staff's concern described in RAI 3.0.3-1-FWS-8 is resolved.

Enhancement 25. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to state that coatings that do not meet acceptance criteria will be repaired or replaced. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2013-01 and finds it acceptable because repairing or replacing coatings that do not meet acceptance criteria is consistent with LR-ISG-2013-01, which ensures that unacceptable coatings will not affect the intended function of the fire water tank.

Enhancement 26. As amended by letter dated August 19, 2015, the applicant stated an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to include requirements associated with follow-up coating inspections, actions, and tests prior to returning a fire water tank to service with degraded coatings (i.e., delamination, peeling, blistering). These include: (a) removal of blisters in excess of a few small intact blisters or blisters not completely surrounded by coating bonded to the substrate, (b) removal of delaminated or peeled coatings, (c) adhesion testing conducted in accordance with standards cited in RG 1.54, (d) feathering of the outermost coating and adhesion testing of the surface surrounding the feathering, (e) ultrasonic testing when there is evidence of pitting or crevice corrosion, (f) an evaluation to ensure that downstream flow blockage is not an issue, and (g) follow-up inspections within 2 years and every 2 years until the coating is repaired, replaced, or removed. The applicant stated that the requirements are not applicable to blisters consisting of, "a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating inspector." The enhancement states that a qualified coating inspector will determine the acceptability of blisters. The "acceptance criteria" program element of AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," recommends that a coating specialist, not a coating inspector, evaluate the acceptability of blisters. A coating inspector might be qualified to lesser requirements than those for a coatings specialist. By letter dated October 29, 2015, the staff issued RAI 3.0.3-1-FWS-11 requesting that the applicant state the basis for using a qualified coating inspector in lieu of a coatings specialist to determine the acceptability of blisters.

In its response dated November 23, 2015, the applicant revised LRA Section A.1.21, Commitment No. 12, and this enhancement to state that a coatings specialist will determine the acceptability of blisters.

The staff finds the applicant’s response acceptable because an individual with the appropriate qualifications will determine the acceptability of blisters. The staff’s concern described in RAI 3.0.3-1-FWS-11 is resolved.

The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2013-01 and finds it acceptable because the inspections, actions, and tests are consistent with the “corrective action” program element of AMP XI.M42 and are capable of ensuring that the degraded coating does not result in a loss of intended function of the component or downstream components. Allowing the return to service of a few small intact blisters surrounded by coating bonded to the substrate is consistent with the “acceptance criteria” program element of AMP XI.M42.

Enhancement 27. As amended by letter dated August 19, 2015, the applicant stated an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to conduct one or more inspections or tests whenever coating conditions such as cracking, peeling, blistering, delamination, rust, or flaking are identified during inspections. The tests include lightly tapping the coating to detect degraded conditions, dry film thickness measurements, wet-sponge testing, adhesion testing, and ultrasonic examinations. The staff reviewed this enhancement against the “detection of aging effects” program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because the inspections and tests will be part of or supplement the minimum level of tests and inspections for degraded coatings and returning a fire water tank to service with degraded coatings as documented in Exception No. 6.

Enhancement 28. As amended by letter dated November 6, 2014, the applicant stated an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the fire water system procedures will be revised to incorporate: (a) inspections for possible voids beneath the fire water tanks, (b) inspection of the vortex breaker in the fire water tanks, (c) qualification requirements for coating inspectors (ANSI 45.2.6, “Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants”), (d) qualification requirements for nuclear coatings specialist (ASTM D7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist), and (e) a requirement for the nuclear coatings specialist to evaluate inspection findings and prepare post-inspection reports.

The staff reviewed this enhancement against the “detection of aging effects” program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable based on the following. Inspections for voids underneath the fire water tanks and the vortex breaker are consistent with NFPA 25 Sections 9.2.6.5 and 9.2.6.7, respectively. The staff noted that examiner qualifications meeting the recommendations in RG 1.54 are consistent with draft LR-ISG-2013-01. The staff finds the use of ANSI N45.2.6 to qualify examiners acceptable because the ANSI N45.2.6 certification is an acceptable basis for qualifying coatings inspectors based on RG 1.54, June 1973, Section C.1., which mandates conformance to the ANSI N45.2 QA standards. The staff finds the use of ASTM D7108-05 to qualify nuclear coatings specialist, because it is cited as an appropriate standard for this purpose in RG 1.54. Having the nuclear coatings specialist evaluate inspection findings and prepare post-inspection reports is consistent with LR-ISG-2013-01.

Summary. Based on its audit and review of the application, and review of the applicant’s responses to RAIs B.1.21-2, B.1.21-2a, B.1.21-4, B.1.21-5, 3.0.3-1-FWS-1, 3.0.3-1-FWS-1a, 3.0.3-1-FWS-2, 3.0.3-1-FWS-3, 3.0.3-1-FWS-4, 3.0.3-1-FWS-5, 3.0.3-1-FWS-6, 3.0.3-1-FWS-8, 3.0.3-1-FWS-9, 3.0.3-1-FWS-10, and 3.0.3-1-FWS-11, the staff finds that the program elements are consistent with the corresponding program elements of LR-ISG-2012-02 AMP XI.M27 and LR-ISG-2013-01. The staff also reviewed the exceptions associated with the "detection of aging effects" program element, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "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.1.21 summarizes operating experience related to the Fire Water System Program. The LRA states that sprinkler system functional testing has been performed in 2004, 2006, and 2008 with no significant discrepancies noted. The LRA also states that yard hydrant flow tests in 2005 and 2007 identified a stuck-closed valve and a broken handwheel on a hose isolation valve, which were repaired and returned to service. The applicant further states that deluge system inspections have identified nozzle blockages that were cleaned and returned to service. LRA Section B.1.2, "Aboveground Metallic Tanks," Program describes visual inspections of the fire water tanks that were conducted in 2007, 2008, and 2009. These inspections detected indications of degradation that were resolved prior to any loss of 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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. As amended by letters dated August 19, 2015, and November 23, 2015, LRA Section A1.21 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 LR-ISG-2012-02 and LR-ISG-2013-01 SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 12) to enhance the program as described above prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later. Based on the changes to LRA Section A1.21 dated August 19, 2015, the previous RAIs related to the USFAR supplement (RAI B.1.21-1 and RAI 3.0.3-1-FWS-7) are no longer applicable. 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 applicant's Fire Water System 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.M27. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 12 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. 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 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. LRA Section B.1.22, as modified by letter dated December 20, 2013, describes the existing Flow-Accelerated Corrosion Program as consistent, with an exception and enhancements, with GALL Report AMP XI.M17, “Flow-Accelerated Corrosion.” The LRA states that this program manages wall thinning for piping and components by performing appropriate analysis and baseline inspections, determining the extent of thinning, performing follow-up inspections, and taking corrective actions as necessary. The LRA also states that the program follows the guidance in NSAC-202L.

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.M17. 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 RAIs, as discussed below.

The “program description” program element in SRP-LR Section A.1.2.3.1 states that the scope of the program should include the specific components that are being managed by the program. The program basis documents reviewed during the audit state that this program is being used to manage aging effects of components in the RCS, the RHR system, the reactor core isolation cooling (RCIC) system, and nonsafety-related systems. During the audit, the staff reviewed calculation MC-Q1111-0811, “Evaluation of RF16 Flow-Accelerated Corrosion Wall Thickness Data,” which states that this program also manages wall thinning in the low-pressure core spray (LPCS) and HPCS systems. However, LRA Tables 3.2.2-2 and 3.2.2-3, which address these two systems, do not list the Flow-Accelerated Corrosion Program as an applicable AMP. By letter dated April 25, 2012, the staff issued RAI B.1.22-1 requesting that the applicant either revise the appropriate tables and sections in the LRA to reflect the Flow-Accelerated Corrosion Program as an AMP that manages components in the LPCS and HPCS systems or provide the appropriate AMP that manages the aging effect being trended in calculation MC-Q1111-08011 for these systems.

In its response dated May 25, 2012, the applicant stated that calculation MC-Q1111-0811 listed the time in service for the LPCS and HPCS systems as less than 2 percent of the time, which results in these systems not being susceptible to flow-accelerated corrosion. The applicant concluded that wall thinning due to this aging effect was not required to be managed for these systems and no revision to the LRA was required. The applicant further stated that no other systems have aging effects being managed by the Flow-Accelerated Corrosion Program that were not identified in the LRA.

However, during its audit, the staff identified that there are six items associated with the LPCS and eight items associated with the HPCS system that have been or are currently being monitored for wall thinning in the Flow-Accelerated Corrosion Program. In addition, the staff identified several items associated with the RHR system that are being monitored for wall thinning in portions of the system that were determined to be not susceptible to flow-accelerated corrosion. It was not clear to the staff whether the susceptibility evaluation had improperly excluded systems or portions of systems that were susceptible to flow-accelerated corrosion, or whether the flow-accelerated corrosion program is monitoring wall thinning for components that are susceptible to an aging mechanism other than flow-accelerated corrosion. In order to resolve this issue, by letter dated September 5, 2012, the staff issued RAI B.1.22-1a requesting the applicant to explain why components in the LPCS, HPCS, and RHR systems are being monitored for wall thinning through the Flow-Accelerated Corrosion Program.

In its response dated October 2, 2012, the applicant stated that various components in the LPCS and HPCS are included in the Flow-Accelerated Corrosion Program for monitoring and evaluations in future outages. The applicant stated that these components had been added to the program based on GGNS operating experience with a pinhole leak in a minimum flow line of the RHR system in 2001. The applicant further stated that GGNS also includes components in the Flow-Accelerated Corrosion Program that had initially been excluded through the program's system susceptibility evaluation, but had since been included based on operating experience, heavily throttled piping regions, cavitation concerns, and EPRI suggestions. Since the GGNS Flow-Accelerated Corrosion Program also addresses loss of material due to mechanisms other than flow-accelerated corrosion, the applicant stated that this is considered an exception to GALL Report AMP XI.M17. Consequently, the applicant modified LRA Sections A.1.22 and B.1.22 to reflect this new position. In addition, the applicant modified LRA Tables 3.2.2-2, 3.2.2-3, 3.2.2-8-2, 3.2.2-8-3, 3.3.2-1, 3.3.2-6, 3.3.2-19-1, 3.3.2-19-8, 3.3.2-19-20, 3.4.2-2-4, 3.4.2-2-6, and 3.4.2-2-11 by adding a new item for piping components exposed to treated water in the associated systems that are managed for loss of material by the Flow-Accelerated Corrosion Program.

In reviewing the above response, the staff noted that the applicant only cited an exception to the "scope of program" program element by stating that the program also includes loss of material due to erosion mechanisms. The staff did not consider this to be a comprehensive evaluation of the changes needed to describe the current program. In addition, the item added to the LRA tables by the applicant applies to wall thinning due to flow-accelerated corrosion, and as noted by the applicant, the associated components are being managed for wall thinning due to mechanisms other than flow-accelerated corrosion. The staff did not consider this to be an appropriate change. In order to address this, by letter dated November 20, 2012, the staff issued RAI B.1.22-1b requesting that the applicant provide additional bases to justify the exception to the program by addressing any needed changes to the aging management program elements and to provide additional detail in the LRA for these components such that the AMR items associated with the erosion aging mechanism are identified.

In its response dated December 18, 2012, the applicant stated that it had reviewed the program elements in GALL Report AMP XI.M17 and provided a more comprehensive discussion for the "detection of aging effects," "monitoring and trending," and "corrective action" program elements. The applicant concluded that, in addition to the "scope of program" program element, it needed to address an exception to the "monitoring and trending" program element because it discusses the use of predictive computer code, CHECWORKS, which does not consider erosion mechanisms. The staff evaluated this exception to GALL Report AMP XI.M17 as discussed below in the Exception section. In addition, the applicant provided further revisions to the LRA tables, which are discussed above for RAI B.1.22-1a. The applicant deleted the existing aging management review item and instead cited items with generic note H and plant-specific notes to indicate that the Flow-Accelerated Corrosion Program also manages carbon steel piping components for loss of material due to erosion mechanisms other than flow-accelerated corrosion. For the "corrective action" program element, the applicant stated, if degradation is due to erosion, that it is not acceptable to only replace the component with more resistant material and that monitoring of the replaced component at an appropriate frequency is warranted.

In its review of the above response, the staff finds portions of the applicant's response acceptable because the applicant accurately described the differences between the program elements described in GALL Report AMP XI.M17 and the corresponding elements in its Flow-Accelerated Corrosion Program. In addition, to clearly reflect the aging mechanism being managed by its Flow-Accelerated Corrosion Program, the applicant provided revised AMR items, which are not addressed in the GALL Report. However, the staff noted that, although the implementing procedure, EN-DC-315, "Flow-Accelerated Corrosion Program," states that it can be used as a guide for evaluating systems and components that are not included in the Flow-Accelerated Corrosion Program, there is no guidance regarding management of non-flow-accelerated corrosion wall-thinning mechanisms. In addition, the staff noted that the applicant's response to RAI B.1.22-1a states that flow-accelerated corrosion location No. 662, which was being managed for erosion, "was replaced in 2004 with FAC-resistant material (stainless steel) and is no longer monitored for FAC." This was contrary to the applicant's above statement regarding the "corrective action" program element. In order to address this discrepancy, by letter dated November 21, 2013, the staff issued RAI B.1.22-1c requesting that the applicant provide additional bases to justify the use of its Flow-Accelerated Corrosion Program to manage components susceptible to non-flow-accelerated corrosion mechanisms.

In its response dated December 20, 2013, the applicant provided an additional enhancement to revise Flow-Accelerated Corrosion Program documentation to specify that components subject to non-flow-accelerated corrosion wall-thinning mechanisms, that are replaced with alternative materials, will continue to be periodically monitored at a frequency commensurate with their post-replacement wear rates and operating times. The staff finds the applicant's response acceptable because the applicant revised LRA Sections A.1.22 and B.1.22 to reflect that the Flow-Accelerated Corrosion Program will be enhanced to specifically address how the program manages components with non-flow-accelerated corrosion-related wall-thinning mechanisms. The staff's concerns described in RAI B.1.22-1, RAI B.1.22-1a, RAI B.1.22-1b, and RAI B.1.22-1c are resolved.

The "monitoring and trending" program element in GALL Report AMP XI.M17 states that inspection results are evaluated to determine if additional inspections are needed to ensure that corrective actions are adequately identified. Procedure EN-DC-315, "Flow-Accelerated Corrosion Program," Section 5.11, "Components Failing to Meet Initial Screening Criteria," states that a condition report shall be generated when "significant wall thinning," as defined in the procedure, is detected. However, during the audit, a search of condition reports generated during recent outages only identified condition reports where wall thinning was reported to be below the minimum acceptable wall thickness, and none appeared to report "significant wall thinning," which is a precursor condition when the wall thickness is above the minimum acceptable value. By letter dated April 25, 2012, the staff issued RAI B.1.22-2 requesting the applicant to confirm that significant wall thinning, as defined in EN-DC-315, had not been detected and condition reports were not required to be generated in recent outages, or provide actions taken if the activities prescribed in EN-DC-315 were not conducted.

In its response dated May 25, 2012, the applicant stated:

> A review of program documentation and data from the fall 2008 and spring 2010 refueling outages determined that no significant wall thinning has been detected

other than the wall thinning documented in the condition reports referenced in the background of this request for information, which had resulted in wall thickness below the minimum acceptable wall thickness. Thus no additional condition reports on significant wall thinning as defined in EN-DC-315 were required to be generated.

However, during its audit, the staff identified several instances, specifically item 314a, item 353, and item 795, where the measured wall thickness was less than 60 percent of nominal pipe wall thickness, which meets the criteria for "significant wall thinning" in EN-DC-315. Based on this, the applicant did not appear to be implementing the program in accordance with the controlling procedures. In order to resolve this issue, by letter dated September 5, 2012, the staff issued RAI B.1.22-2a, requesting the applicant to re-verify that significant wall thinning, as defined in EN-DC-315, had not been detected and condition reports were not required to be generated in recent outages, or to provide actions taken if the activities prescribed in EN-DC-315 were not conducted.

In its response dated October 2, 2012, the applicant stated that it had performed a further review of program documentation and had identified an incorrect interpretation of the procedural requirements to generate condition reports with respect to significant wall thinning for the items cited in the RAI. The applicant stated that the incorrect interpretation had been documented in the CAP. The applicant further stated that all of the associated components had been replaced with "FAC-resistant" material during either the 2010 or 2012 refueling outages. The applicant concluded that the material replacements indicate that the program remains effective for managing the effects of aging and that corrective actions to address the incorrect procedure interpretation will ensure that the program will be implemented in accordance with the controlling procedures during the period of extended operation. The staff finds the applicant's response acceptable because the applicant acknowledged its incorrect interpretation of the procedural requirements in EN-DC-315 and documented the issue in its CAP. The staff notes that the applicant has taken measures to ensure that the intended function of the components in question will be maintained in accordance with the CLB by replacing them with material that is resistant to flow-accelerated corrosion. The concerns described in RAI B.1.22-2a are resolved.

The "program description" program element in GALL Report AMP XI.M17 states that the flow-accelerated corrosion program addresses carbon steel components containing high-energy fluids. However, during the audit, the staff identified several condition reports that referred to GGNS MS-46, "Program Plan for Monitoring Internal Erosion/Corrosion in Moderate Energy Piping Components, (Safety Related)." Since this program defines "erosion/corrosion" almost the same as EN-DC-315 defines "flow-accelerated corrosion" for high-energy systems, it was not clear whether GGNS MS-46 also monitors flow-accelerated corrosion. By letter dated April 25, 2012, the staff issued RAI B.1.22-3 requesting the applicant to provide information regarding the aging effects being managed by GGNS MS-46 and how it relates to or integrates with the Flow-Accelerated Corrosion Program in the LRA.

In its response dated May 25, 2012, the applicant stated that it does not credit the inspections described in GGNS MS-46 as a separate AMP and that the Flow-Accelerated Corrosion Program does not credit the inspections conducted in GGNS MS-46. The applicant stated, however, that the inspections conducted in GGNS MS-46 are credited as part of the AMPs for managing loss of material in the Fire Water System and Service Water Integrity Programs. The staff finds the applicant's response acceptable because the applicant clarified that it does not credit GGNS MS-46 within the Flow-Accelerated Corrosion Program; however, it does credit the inspections conducted with this procedure for loss of material due to erosion and corrosion in

AMPs for raw water systems. The staff's concern described in RAI B.1.22-3 is resolved. SER Section 3.0.3.1.39 documents additional discussion regarding the use of GGNS MS-46 in the Service Water Integrity Program.

The "detection of aging effects" program element in GALL Report AMP XI.M17 states that the schedule of inspections ensures detection of wall thinning before the loss of intended function. Procedure EN-DC-315 states that a 10 percent safety factor should be applied to account for inaccuracies in the wear rate evaluations. However, calculation MC-Q1111-08011 states that for systems which only operate part-time, it is acceptable to use grid-synchronized hours in calculating the wear rate, because it "…provides a valid relative measure of wear for whatever number of hours each system actually operated…." The calculation also states that the infrequently operated systems "…are expected to be operated in the future similar to how they have been operated in the past…" and states that the RCIC system is assumed to operate 12 hours per year. Since relatively small increases in operating times (i.e., 1.2 hours for the RCIC system) could "consume" all of the uncertainty being applied in the 10 percent safety factor, which would not leave any margin for other uncertainties (e.g., UT inaccuracies), it was not clear to the staff whether the 10 percent safety factor is adequate for systems operating infrequently. By letter dated April 25, 2012, the staff issued RAI B.1.22-4 requesting the applicant to provide information to assure that the 10 percent safety factor, used in the wear-rate evaluations, accounts for wear-rate-measurement uncertainties due to variations in assumed operating times for systems operating infrequently.

In its response dated May 25, 2012, the applicant stated that although the RCIC system operates less than 2 percent of the time, it has conducted inspections at multiple locations in that system under the Flow-Accelerated Corrosion Program and has confirmed that wear is not a concern for infrequently-operated systems. The applicant also stated that the 10 percent safety factor is used in conjunction with other considerations, including personnel safety and consequence of failure, and that the lack of wear identified in infrequently-operated systems provides reasonable assurance that variation in system operating time is not a concern. The staff finds the applicant's response acceptable because although the system usage may exceed the values assumed in the calculation, the applicant has inspected infrequently-operated systems and has confirmed that the wear rates are low, which compensates for the uncertainties due to potential underestimation of the overall wear. The staff's concern described in RAI B.1.22-4 is resolved.

The "monitoring and trending" program element in GALL Report AMP XI.M17 states that, based on the results of a predictive code such as CHECWORKS, the inspection schedule the applicant developed provides reasonable assurance that structural integrity will be maintained between inspections. During the audit, the staff reviewed condition report, CR 2010-00823, which described an error, reported by the Electric Power Research Institute (EPRI) in its CHECWORKS model software, regarding the use of incorrect hours to calculate the predicted wear. The condition report stated that of the 122 instances where the specific software feature was used, only 7 wear rate analyses were potentially affected due to the error and that further evaluations concluded there was no impact on the wear-rate calculations. The condition report also stated that CHECWORKS is only one tool the flow-accelerated corrosion engineer used to determine component wear. It was not clear to the staff what other tools are used to determine component wear such that errors in the CHECWORKS software model will be detected. By letter dated April 25, 2012, the staff issued RAI B.1.22-7 requesting the applicant to describe any in-place process or verification method, which is used to determine component wear that validates and could compensate for errors in the CHECWORKS software, such that structural integrity will be maintained between inspections.

In its response dated May 25, 2012, the applicant stated that the results of component inspections are the primary input used in the calculation to schedule the next inspection, and that as more actual inspection data are acquired, the already limited reliance on CHECWORKS becomes less. The applicant also stated that this approach provides reasonable assurance that an error in the CHECWORKS model software will not prevent the program from providing reasonable assurance that the intended function of components will be maintained. In its review of the applicant's response, however, it was unclear to the staff whether the applicant independently calculated wear rates without CHECWORKS since the CHECWORKS-calculated wear rates can be based on the component inspection data. In addition, the RAI response did not describe the other tools discussed in the condition report that are used to determine component wear. In order to address this concern, by letter dated August 21, 2012, the staff issued RAI B.1.22-7a, requesting the applicant to describe the other tools used to determine component wear, and to explain how the use of component inspection results reduces the effects of any errors in CHECWORKS.

In its response dated September 13, 2012, the applicant provided the factors it uses to select locations for outage inspections and stated that the measured wall thickness is compared to the predicted value for every component where the CHECWORKS prediction is the basis of the selection. The applicant also stated that the actual measured wall thickness data can be used to detect errors in the CHECWORKS software. The applicant also provided its process steps for determining component wear, which included calculating the projected wear rate by using the change in measured wall thickness data and the operating time between measurements. The staff finds the response acceptable because the applicant's process, which independently calculates wear rates and compares the predicted values to actual measured wall thickness data, is capable of compensating for the type of CHECWORKS software error discussed in the condition report, thereby providing reasonable assurance that effects of aging will be adequately managed to maintain intended functions consistent with the CLB. The staff's concerns described in RAIs B.1.22-7 and B.1.22-7a are resolved.

The staff also reviewed the portions of the "scope of program" and "corrective actions" program elements associated with the exception and enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancement follows.

Exception. The applicant acknowledged an exception to the "scope of program" and "monitoring and trending" program elements in responses to RAIs B.1.22-1a and B.1.22-1b, dated October 2, and December 18, 2012, respectively. In this exception, the applicant stated that the GGNS Flow-Accelerated Corrosion Program addresses loss of material due to mechanisms other than flow-accelerated corrosion that are identified through plant-specific and industry operating experience. The applicant justified this exception by stating that, although a predictive model is not applicable, the program provisions for identifying inspection locations based on operating experience are applicable and appropriate for mechanisms other than flow-accelerated corrosion. The applicant noted in its response to RAI B.1.22-1b that it does not remove components from the program that have been replaced with "FAC-resistant" or "erosion-resistant" materials and that inspections of replaced components continue on a schedule that ensures wall thinning does not exceed acceptable values. However, the staff noted that the applicant's response to RAI B.1.22-1a states that flow-accelerated corrosion location No. 662, which was being managed for erosion, "was replaced in 2004 with FAC-resistant material (stainless steel) and is no longer monitored for FAC." This discrepancy between how the program is intended to work compared to how it appears to be implemented was addressed in

RAI B.1.22-1c, previously discussed above, and resulted in an additional enhancement to the program, as discussed below.

The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M17 and finds it acceptable because the current industry guidance, NSAC-202L, contains provisions for a category of components that are susceptible to flow-accelerated corrosion, but cannot be accurately modeled by the predictive software due to various complicating factors. NSAC-202L designates this category as susceptible-not-modeled. In addition, the staff agrees that the applicant can manage components that are susceptible to wall-thinning mechanisms other than flow-accelerated corrosion, which cannot be modeled by the predictive software, similar to the way it manages susceptible-not-modeled components that are included in the Flow-Accelerated Corrosion Program.

Enhancement 1. LRA Section B.1.22 states an enhancement to the “corrective actions” program element. In this enhancement, the applicant stated that, when upstream components are replaced with resistant material, such as high chromium material, the downstream components will be closely monitored for any increased wear. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M17 and finds it acceptable because when implemented, it will detect any increase in wear rate that has been noted in the industry on components downstream of those replaced with stainless steel.

Enhancement 2. As a result of RAI B.1.22-1c, by letter dated December 20, 2013, the applicant revised LRA Section B.1.22 to implement an additional enhancement to the “corrective actions” program element. In this enhancement, program documentation will be revised to specify that components subject to wall-thinning mechanisms other than FAC, which are replaced with alternate materials, shall continue to be periodically monitored at a frequency commensurate with their post-replacement wear rates and operating times. The staff reviewed this enhancement against the guidance in LR-ISG-2012-01, “Wall Thinning Due to Erosion Mechanisms,” and finds it acceptable because corrective actions will require periodic monitoring for components replaced with an alternate material, since a material completely resistant to a non-FAC mechanism such as erosion is not available.

Summary. Based on its audit of the applicant’s Flow-Accelerated Corrosion Program and review of the applicant’s responses to RAIs B.1.22-1, B.1.22-1a, B.1.22-1b, B.1.22-1c, B.1.22-2, B.1.22-2a, B.1.22-3, B.1.22-4, B.1.22-7, and B.1.22-7a, 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.M17. The staff also reviewed the exception and its justification associated with the “scope of program” and “monitoring and trending” program elements and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff also reviewed the enhancement associated with the “corrective actions” program element and finds that when implemented they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.22 summarizes operating experience related to the Flow-Accelerated Corrosion Program. The LRA discusses the evaluation of wall thickness data from refueling outage 14 (RF14) in 2005 and noted that all items inspected were acceptable for continued service beyond RF15. The LRA also discussed the evaluation of wall thickness data from RF16 in 2008 and noted that, except for three components, all items inspected were acceptable for continued service beyond RF17. The LRA states that condition reports were issued for each of the three components and each was repaired. The LRA also cited a

2009 program assessment report that stated the identification of program deficiencies and subsequent corrective actions provide assurance that the program will remain effective.

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 AMP 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 RAIs, as discussed below.

SRP-LR Section A.1.2.3.10, “Operating Experience,” states that operating experience, which results in program enhancements or additional programs, should be considered. In its review of Calculation MC-Q1111-08011, item 809 states that the reactor water cleanup bottom head drain lines are an operating experience issue and that BWRVIP-205, “Bottom Head Drain Line Inspection and Evaluation Guidelines,” changed GGNS to a category that requires an inspection within two outages of November 2008. The staff noted that BWRVIP-205 was not listed in LRA Appendix C, “Responses to BWRVIP Applicant Action Items,” and it was unclear whether the inspections prescribed in BWRVIP-205 will be performed and whether they are being tracked under the Flow-Accelerated Corrosion Program or the Reactor Vessel Internals Management program. By letter dated April 25, 2012, the staff issued RAI B.1.22-5, requesting the applicant to provide the status of the prescribed inspections and to either provide an enhancement to the Flow-Accelerated Corrosion Program to include these inspections or provide the bases for concluding these inspections do not need to be performed.

In its response dated May 25, 2012, the applicant stated that it had performed the inspections prescribed in BWRVIP-205 during the refueling outage in spring 2012 and had projected the limiting location to be acceptable until at least spring 2022. The applicant also stated that the drain line is included in the Flow-Accelerated Corrosion Program, which ensures the future inspections will be conducted. The staff finds the applicant’s response acceptable because the bottom head drain line was inspected as prescribed by BWRVIP-205, and this line had been added to the Flow-Accelerated Corrosion Program. The staff’s concern described in RAI B.1.22-5 is resolved.

SRP-LR Section A.1.2.3.10, “Operating Experience,” states that operating experience should result in appropriate program enhancements and show where an existing program has failed in intercepting aging degradation in a timely manner. The staff’s review of Calculation MC-Q1111-08011, item 355, and item 553 identified that the measured wall thickness was less than minimum wall thickness, and the projected life for each item indicated that the minimum wall thickness criterion was not met more than 3 years prior to the inspection. Although condition reports were initiated and the inspection scope was appropriately increased, based on the calculated wear rates, the staff questioned the effectiveness of the program because inspections are typically planned prior to violating the minimum wall thickness criterion. By letter dated April 25, 2012, the staff issued RAI B.1.22-6 requesting the applicant to discuss the circumstances surrounding the apparent weakness in scheduling inspections for item 355 and item 553 and to include corrective actions or enhancements to the program taken as a result of these plant-specific operating experiences.

In its response dated May 25, 2012, the applicant stated that item 355 addressed a shell drain nozzle of a moisture separator reheater and that the low thickness reading was at a localized area. The applicant stated that the nozzle was repaired using a weld overlay and that based on the nozzle's average wall thickness being well-above the minimum code required thickness, there was no need for a specific program enhancement. The applicant also stated that item 553, pertains to a socket welded fitting downstream of an orifice in a 2-inch bypass line to the high-pressure condenser shell. The applicant stated that the inspections in fall 1999 and fall 2005 had concluded that wear at this location remained fairly constant; however, the wear rate increased significantly between the inspections in fall 2005 and fall 2008 inspections. The applicant further stated that it had replaced this bypass line and another line that experienced similar operating conditions with stainless steel material during the fall 2010 refueling outage to manage the effects of aging. The staff finds the applicant's response acceptable because the circumstances surrounding these apparent weaknesses in inspection scheduling are not straightforward such that the wear could not be reasonably foreseen. In addition, the staff considers the applicant's corrective actions to be sufficient to preclude the need for specific enhancements to the program. The staff's concerns described in RAI B.1.22-6 are resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs B.1.22-5 and B.1.22-6, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.22, as amended by letter dated October 2, 2012, in response to RAI B.1.22-1a, and by letter dated December 20, 2013, in response to RAI B.1.22-1c, 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 also noted that the applicant committed (Commitment No. 13 and No. 36) to enhance the Flow-Accelerated Corrosion Program prior to November 1, 2024, (a) to specify that downstream components are monitored closely to mitigate increased wear when susceptible upstream components are replaced with resistant materials such as high chromium, and (b) to require periodic monitoring for components replaced with an alternate material when they are subjected to a non-flow-accelerated corrosion wall-thinning mechanism. The staff finds 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 applicant's Flow-Accelerated Corrosion Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program element of GALL Report AMP XI.M17. In addition, the staff reviewed the exception and its justification and determined that the AMP, with the exception, is adequate to manage the applicable aging effects. The staff also reviewed the enhancements and confirmed that their implementation through Commitments No. 13 and No. 36 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.22 Inservice Inspection

Summary of Technical Information in the Application. LRA Section B.1.23 describes the existing Inservice Inspection (ISI) Program as consistent with GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." It states that this program manages aging effects for ASME Class 1, 2, and 3 pressure-retaining components within the scope of license renewal. The LRA also states that this program includes volumetric, surface, and visual examinations of Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting.

The applicant further stated that this program is updated every 10 years to the latest ASME Code Section XI edition and addendum the NRC approved in 10 CFR 50.55a.

In addition, the applicant stated that its ISI Program summary reports between 2004 and 2010 reveal compliance (including evaluation or repair of indications/flaws) and provide evidence that the program is effective for managing aging effects in accordance with the ASME Boiler Pressure Vessel Code Section XI.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report AMP XI.M1. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

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 in lieu 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 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 with 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. The applicant's ISI Program is currently in its third 10-year ISI interval, which began on July 1, 2005. The current Code of record for the applicant's ISI Program is the 2001 Edition through the 2003 Addenda of the ASME Code.

During its review, the staff noted Event Notification Report No. 47880, dated April 30, 2012, indicating that the applicant detected an unacceptable indication in one of the RHR systems to reactor pressure vessel nozzles (weld area of N06B-KB nozzle) during its refueling outage in May 2012. The defect has a size of 0.9 inch in length and 0.5 inch in depth. Nominal wall thickness of the weld is 1.3 inches. The staff needed clarification on the effectiveness of the applicant's AMP (e.g., detection of aging effects and directing corrective actions in a timely manner). By letter dated June 27, 2012, the staff issued RAI B.1.23-2 requesting that the applicant clarify whether the defect detected in the RHR nozzle is age-related. The RAI also requested the applicant to clarify when the previous UT examination was performed on the subject RHR weld and describe adequacy of its corrective actions and extent of condition performed. The RAI further requested that the applicant provide justification that the current inspection schedule for all affected components is adequate for timely detection of aging effects.

In its response dated July 26, 2012, the applicant stated that the indication detected was attributed to the aging mechanism of IGSCC, similar to IGSCC cracks found in DM welds at other BWRs. Regarding previous UT examination performed on this weld, the applicant stated that the previous examination was performed during the fall 2002 refueling outage and no indications were identified at the time. Regarding its corrective actions and extent of condition, the applicant stated that there are thirty-four DM welds that require inspection under BWRVIP-75-A. Twenty DM welds were inspected prior to RF18. The remaining 14 welds in the program were inspected during RF18. All welds of this type have been inspected with no other flaws detected. The applicant further stated that the corrective action implemented to correct the indication identified during RF18 included a full structural weld overlay. The staff noted that the applicant performed a full structural weld overlay to mitigate the flaw, an industry repair methodology approved by the staff. The staff also noted that the applicant followed BWRVIP-75-A, a staff-approved industry program, and performed UT examinations on all its required DM welds. The staff finds the applicant's response acceptable because the applicant performed appropriate corrective action to mitigate the flaw and performed adequate extent of condition that resulted in the applicant inspecting all DM welds of the same type, a total of 34 DM welds. In addition, no other indications were detected from the UT examinations of all other similar DM welds. Therefore, the staff's concern described in RAI B.1.23-2 is resolved.

Based on its audit and review of the LRA and the applicant's responses to RAIs, the staff finds that elements one through six of the applicant's Inservice Inspection Program are consistent with the corresponding program elements of GALL Report AMP XI.M1 and, therefore, acceptable.

Operating Experience. LRA Section B.1.23 summarizes operating experience related to the Inservice Inspection Program. The applicant indicated that this program is based on the ASME Code Section XI, Subsections IWB, IWC, and IWD, which is based on industry-wide operating experience, research data, and technical evaluations.

The staff noted that GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," states that the program "has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light-water cooled power plants." It also provides industry operating experience cases in the "operating experience" program element. However, the LRA does not provide any detailed discussion to demonstrate the effectiveness of the program in detecting and managing the aging effects of Class 1, 2, or 3 components in a timely manner. In addition, the applicant's ISI Program summary reports between 2004 and 2010 provide brief inspection results to establish the program's compliance with the ASME Code, but do not provide any discussion to demonstrate the program effectiveness in the context of monitoring, detecting, and correcting aging degradation. Therefore, by letter dated April 3, 2012, the staff issued RAI B.1.23-1 requesting that the applicant provide detailed representative operating experience related to the applicant's Inservice Inspection Program to demonstrate the program's effectiveness in managing aging effects during the period of extended operation.

In its response dated May 1, 2012, the applicant provided specific operating experience cases related to the implementation of its ISI Program. For example, as part of the ISI Program inspection in 2004, the applicant's examinations identified linear indications in numerous CRD cap-screws. As a result, the applicant performed a metallographic examination and engineering evaluation on five CRD cap screws with the most significant indications and determined the condition of the cap-screws were acceptable for continued service. In addition, as CRDs were replaced, they were inspected by VT-1 and those with unacceptable indications were subjected to eddy current examination to verify the surface indication did not extend beyond the acceptable depth. Furthermore, for cap screws with indications that exceeded the established limit on flaw depth, a condition report was initiated by the applicant to evaluate the condition and effect appropriate corrective actions. This experience demonstrated that the applicant's ISI Program is able to detect minor indications of potential degradation before a loss of the component's license renewal-intended function. In its response, the applicant provided a second example. During the same outage inspection, deficiencies were found in pipe supports in the SSW cooling tower basin, which resulted in engineering evaluations, extent of condition, and repairs. In addition, follow-up inspections by the applicant's ISI Program confirmed that repairs were made in satisfactory condition. The staff finds the applicant's response acceptable because the applicant provided discussion of plant-specific operating experience that demonstrates the effectiveness of the program by detection of aging effects and directing corrective actions in a timely manner. Therefore, the staff's concern described in RAI B.1.23-1 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.1.23-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.23 provides the UFSAR supplement for the Inservice Inspection Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with 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.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Inservice 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).

3.0.3.1.23 Inservice Inspection – IWF

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.24 describes the existing Inservice Inspection – IWF Program as consistent, with enhancements, with GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF." The LRA states that the Inservice Inspection – IWF Program manages aging effects for ASME Class 1, 2, and 3 and component supports. The LRA also states that the scope of inspection for component supports is based on sampling of piping supports and 100 percent of component supports other than piping as specified in Table IWF-2500-1. The applicant's AMP basis document, which the staff reviewed

on site, states that the AMP manages aging through visual inspection in accordance with ASME Section XI, Subsection IWF. During its audit, the staff confirmed that the applicant does not have any ASME Code Class MC supports.

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.S3. For the "preventive actions" and "monitoring and trending" 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.S3 recommends that the selection of bolting material installation torque or tension and the use of lubricants and sealants be in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," to prevent or mitigate degradation and failure of structural bolting. These EPRI documents and NUREG-1339 discuss the detrimental effects of using molybdenum disulfide lubricant because lubricants containing molybdenum disulfide have been shown to contribute to SCC. The GALL Report states that if the structural bolting consists of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and SCC potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," need to be considered.

During its audit, the staff reviewed the applicant's Inservice Inspection – IWF AMP, which states that the site maintenance procedures that provide technical guidance to torquing procedures recommend using molybdenum disulfide. The AMP states that it is assumed that all high-strength structural bolting material (i.e., ASTM A325 and A490) has used this lubricant in the torquing process during construction and maintenance activities for the life of the plant so far. During its onsite review, the staff noted that the AMP states that plant procedures will be enhanced to prohibit the use of molybdenum disulfide; however, the AMP does not address how and when bolts previously torqued using molybdenum disulfide lubricant will be inspected for degradation. The AMP also does not specify that the program will require that the selection of bolting material installation torque or tension and the use of lubricants and sealants will be in accordance with EPRI NP-5769, EPRI TR-104213, and NUREG-1339. The staff questioned whether the applicant's program will be in accordance with the above guidance for bolting material, as well as the guidance of RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for structural bolts. Therefore, by letter dated May 9, 2012, the staff issued RAI B.1.24-5 requesting that the applicant describe the plan, including sample size and frequency, for inspecting high-strength bolts previously torqued using molybdenum disulfide lubricant.

In its response dated June 6, 2012, the applicant stated that the ISI-IWF Program addresses the potential for SCC for high-strength bolts for nuclear steam supply system component supports by including sample size and frequency for bolts that may have been previously torqued using molybdenum disulfide. The applicant also stated that it is augmenting its program to include volumetric examination of high-strength structural bolting. The staff noted that the applicant's response did not indicate whether the applicant's procedures will implement the guidance recommended in the GALL Report or follow the preventive actions for storage, lubricants, and SCC potential discussed in the RCSC "Specification for Structural Joints using ASTM A325 or A490 Bolts" for high-strength structural bolts. In a letter dated September 5, 2012, the staff issued follow-up RAI B.1.24-5a requesting that the applicant clarify (a) if its program will implement the guidelines of EPRI NP-5769, EPRI TR-104213, and NUREG-1339 to prevent or mitigate degradation and failure of structural bolting; and (b) if it will follow the RCSC guidance for ASTM A325 and A490 bolts.

The applicant responded by letter dated October 2, 2012. Part (a) of the applicant's response stated that the existing ASME Section XI Inservice Inspection – IWF Program is a condition monitoring program that does not include guidance for the selection of bolting material, installation torque or tension, and use of lubricants and sealants, but instead is augmented by plant procedures that address that guidance. The applicant stated that it will include an enhancement to incorporate recommendations delineated in NUREG-1339, and EPRI NP-5769 and TR-104213 for high strength structural bolting. The enhancement also states that the recommendations will address proper selection of bolting material, proper installation torque or tension, and the use of appropriate lubricants and sealants. In part (b) of its response, the applicant clarified that site procedures include the guidance of Section 2 of RCSC publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852 and A490 bolting.

The staff finds the applicant's response acceptable because procedures for implementation of the ASME Section XI Inservice Inspection – IWF Program include the guidance of the RCSC publication, which discusses preventive actions for storage, lubricants, and stress corrosion cracking potential for high strength structural bolts. In addition, the implementing procedures for the ASME Section XI Inservice Inspection – IWF Program will incorporate the guidance recommended in GALL Report AMP XI.S3. The staff's concerns described in RAIs B.1.24-5 and B.1.24-5a are resolved.

The "monitoring and trending" program element in GALL Report AMP XI.S3 recommends that examinations that reveal indications that exceed the acceptance criteria of ASME IWF-3410 and require corrective measures are extended to include additional examinations in accordance with IWF-2430. The applicant's AMP basis documentation states that the acceptance criteria are in accordance with ASME IWF-3410. However, during its audit, the staff reviewed results of the 2011 ISI-IWF inspection in which a bolt in the SSW system was found to have degradation that exceeded the acceptance criteria, and the applicant did not provide documentation to indicate that the examination would be extended to include additional examinations or that such examinations had been performed consistent with the GALL Report recommendations and in accordance with the requirements of ASME IWF-2430.

By letter dated May 9, 2012, the staff issued RAI B.1.24-2 requesting that the applicant provide documentation that demonstrates that the Inservice Inspection – IWF Program, as implemented, is consistent with ASME IWF-2430 and Section XI.S3, ASME Section XI, Subsection IWF of the GALL Report, regarding increase in sample size when deficiencies are identified during examination of supports. If additional inspections were not performed, the staff requested that the applicant provide the basis for the statement in LRA Section B.1.24 that the IWF Program is consistent with ASME Code and Section XI.S3 for GALL Report.

In its response dated June 6, 2012, the applicant stated that during the 2003 ISI-IWF inspection, one of the underwater supports was documented as not meeting the acceptance criteria in ASME Section IWF-3000 and the condition was documented in the CAP. The applicant increased the scope of the ISI-IWF inspection in accordance with ASME Section XI, Subsection IWF-2430. The applicant further stated that subsequent ISI-IWF inspections performed after 2004 identified additional supports that did not meet the acceptance criteria requirements in ASME Section IWF-3400, and the conditions were entered into the CAP. The applicant determined that it needed to increase the frequency of the inspections of the underwater supports to include all underwater supports. The applicant finally stated that, since 100 percent of the underwater supports in the SSW basins are inspected, the degraded component found during the 2011 inspection did not result in an expansion of inspection scope.

The staff reviewed the applicant's response and noted that the condition discovered in the 2011 inspection was subsequent to the applicant's previous corrective actions with regard to age-related degradation found in prior inspections. The staff also noted that when a degraded condition was found in 2003, the applicant expanded the inspection scope to include additional supports in the SSW basin and more frequent inspections and that it further expanded the inspection scope to include 100 percent of the supports on a yearly frequency. However, the staff questioned whether there are any IWF supports in other systems that may be subject to a similar material and environment combination and if the scope of additional inspections should be extended to areas beyond the SSW system. The staff needed more information to complete its review. Therefore, by letter dated September 5, 2012, the staff issued follow-up RAI B.1.24-2a and requested that the applicant provide information on whether there are IWF supports in other areas of the plant that may be subject to similar age-related degradation. If so, the staff requested that the applicant provide information as to what additional examinations will be performed, if any.

In its response dated October 2, 2012, the applicant stated that it has not identified ASME Section XI-IWF supports in other areas of the plant that are subject to similar age-related degradation as the degraded supports identified in the SSW basin. The applicant explained that there are in-scope supports in other areas of the plant that are exposed to a fluid environment similar to the SSW basin, such as the suppression pool and spent fuel pool components; however, the materials for those supports are not carbon steel.

The staff finds the applicant's response acceptable because the applicant has considered the susceptibility of IWF components of similar material and environment combination and concluded that there are no IWF components subject to similar aging effects other than those in the SSW system. Also, the applicant now includes 100 percent of underwater supports in the SSW system as a result of as-found degraded conditions in accordance with ASME IWF-2430. The staff's concerns described in RAIs B.1.24-2 and B.1.24-2a are resolved.

During its audit, the staff also noted several cases in which conditions were found during ASME ISI-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 IWF-3410), and the applicant chose to re-work 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 in order 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 IWF supports that are part of the inspection sample are re-worked to as-new condition, that support is no longer typical of the other supports in the population that were not re-worked and in subsequent examinations would not represent the age-related degradation of that population. Therefore, by letter dated May 9, 2012, the staff issued RAI B.1.24-3 requesting that the applicant explain, when corrective actions are not required per the ASME Code Section IWF acceptance criteria, but a support within the IWF inspection sample is found degraded and repaired to as-new condition without an expansion or revision of the IWF sample population, how the IWF Program will be effective in managing aging of similar/adjacent components in that population that are not included in the IWF Program sample.

In its response dated June 6, 2012, the applicant stated that, for conditions when corrective actions are not required per the ISI-IWF acceptance criteria but the support is within the inspection sample, the repair activity is evaluated to determine whether it is a repair or replacement activity or is considered a maintenance activity. The applicant stated that maintenance activities may require the performance of a new ASME Section XI Code examination or test. The applicant also stated that, if a maintenance activity is performed and the activity affects an existing preservice or inservice examination record, then a new preservice examination will be performed.

The staff did not find the applicant's response acceptable because it does not address how the applicant will address age-related degradation of the IWF component population when a support is repaired to a condition that is as-new and then not representative of the rest of the component support population. The GALL Report recommends that the IWF Program use the sampling methodology stated in ASME Table IWB-2500 to inspect and examine for the presence of and extent of aging effects to represent the total population of components, including those that are similar but are outside the inspection sample. Re-working a component or components in the sample before degradation to the ASME IWF-3000 limits, but not (1) replacing that component with one that shows aging representative of the rest of the population, or (2) expanding the inspection sample to include another component that shows aging representative of the remaining population, may make the program unable to detect more severe age-related degradation of components outside the inspection sample that are continuing to degrade. The staff determined that it needed further information to complete its review. Therefore, by letter dated September 5, 2012, the staff issued follow-up RAI B.1.24-3a requesting that the applicant explain how, without either changing the component inspected or expanding the inspection scope, if components determined to be degraded but not exceeding the ASME acceptance criteria for expansion in scope are selectively re-worked, it can ensure that components in the IWF inspection scope are a true representation of the age-related degradation of remaining components in the population.

In its response dated October 2, 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 IWF-3400, an evaluation will be performed in accordance with the CAP. The applicant stated that if the evaluation determines that the component, without repair, will continue to perform its intended function until the next scheduled inspection, the component support will not be repaired but will be monitored for increased degradation. The applicant further stated that the evaluation will also consider which inspections or repairs may be required for similar/adjacent components not included in the ISI program sample population and assure that additional inspections are performed during the next scheduled inspection. As an alternative, the applicant stated that it may choose to repair the degraded component and replace it in subsequent inspection samples with a randomly selected component that is more representative of the general population. The applicant revised LRA Sections A.1.24 and B.1.24 to add this revision as an enhancement to the program.

The staff finds this response acceptable because the applicant's program will ensure that the component supports being examined in the IWF inspection sample are representative of the aging of the total population, thus allowing the program to adequately manage aging of IWF supports and bolting. The staff's concern described in RAIs B.1.24-3 and B.1.24-3a are resolved.

The staff also 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.

<u>Enhancement 1</u>. LRA Section B.1.24 states an enhancement to the "scope of program," program element. In this enhancement, the applicant stated that the ISI-IWF Program will be enhanced to address inspections of accessible sliding surfaces. 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 the GALL Report AMP.

<u>Enhancement 2</u>. LRA Section B.1.24 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that the ISI-IWF Program will be enhanced to clarify that parameters monitored or inspected will include corrosion; deformation; misalignment of supports; missing, detached, or loosened support items; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. The applicant also stated that accessible areas of sliding surfaces, elastomeric vibration isolation elements, and structural bolts will be monitored for all applicable aging effects, which the staff confirmed is consistent with the recommendations of the GALL Report AMP XI.S3. In addition, high-strength structural bolting susceptible to SCC will be monitored for SCC. The staff reviewed these enhancements against the corresponding program elements in GALL Report AMP XI.S3 and finds them acceptable because, when they are implemented, they will make the program consistent with the recommendations in the GALL Report AMP.

<u>Enhancement 3</u>. LRA Section B.1.24 states an enhancement to the "detection of aging effects" program element. In Enhancement 3, the applicant stated that structural bolting (ASTM A325, ASTM F1852, and ASTM A490 bolts) and anchor bolts will be monitored for loss of material, loose or missing nuts, loss of preload, and cracking of concrete around the anchor bolts. 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 the GALL Report AMP.

The applicant also states another enhancement to the "detection of aging effects" program element, that it will perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 for high-strength structural bolting in addition to the VT-3 examination. During its audit, the staff asked the applicant how it will implement the provisions for volumetric examinations, specifically to give the sample size, sampling method, and frequency of volumetric examinations. The applicant stated that it would perform volumetric examinations of any high-strength bolts identified on the component supports that are in the scope of the IWF sample for each inspection interval. The staff noted that the applicant's Inservice Inspection – IWF Program selects component supports for examination in accordance with the ASME Code, which requires 25 percent of Class 1 piping supports, 15 percent of Class 2 supports, and 10 percent of Class 3 supports. The staff determined that the applicant's plans to perform volumetric examination on only the high-strength bolting that is identified on supports that are already within the IWF sample does not necessarily ensure that an adequate number of bolts will be examined in order to effectively manage aging of high-strength bolting. The staff noted that the applicant's original sample selection for the IWF Program did not include high-strength bolting, so there is no assurance that there will be enough bolts identified within the scope of the current IWF sample to ensure a representative sample of the entire population of high-strength structural bolting will be subject to volumetric examination. The staff determined the need for additional information, which resulted in the issuance of an RAI. By letter dated May 9, 2012, the staff issued RAI B.1.24-1 requesting that the applicant describe how the volumetric inspections for the Inservice Inspection – IWF Program will manage cracking for the entire population of high-strength bolts for the period of extended operation.

In its response dated June 6, 2012, the applicant stated that it will enhance the ISI-IWF Program to identify the component supports that contain high-strength bolting (actual yield strength greater than or equal to 150 ksi) in sizes greater than 1-inch nominal diameter and that the frequency and extent of examination for support types that contain high-strength bolting will be as specified in ASME Code Section XI, Table IWF-2500-1. The staff reviewed the applicant's response and could not determine if the applicant plans on identifying the entire population of the high-strength structural bolting in scope for license renewal and then using the sampling provisions of ASME Table IWB- 2500-1. The staff found that the applicant's response was not acceptable because it was not clear that the sampling percentages specified in ASME IWF-2500-1 would be followed for the high-strength bolts as an individual population or if the applicant's plan is to identify high-strength bolts that exist on component supports already identified in the IWF inspection sample. The staff determined that it needed additional clarification to complete its review. Therefore, by letter dated September 5, 2012, the staff issued follow-up RAI B.1.24-1a requesting that the applicant clarify whether it will identify all of the high-strength bolts in the plant that are eligible to be part of the IWF inspection population and establish a sample based on the ASME Table IWF-2500-1 or if it will identify high-strength bolts from the already-established set of IWF supports. If the latter, the staff requested that the applicant explain how that approach will ensure that the ASME Code criteria for sample size will be met.

In its response dated October 2, 2012, the applicant clarified that it will identify all of the component supports that contain high-strength bolting and will examine high-strength structural bolting on the frequency specified in the ASME Code Section XI, Table IWF-2500-1. The staff finds this acceptable because the applicant will define an IWF inspection sample for high-strength bolts that is representative of the high-strength structural bolting components that exist in the plant and because the number of high-strength bolts inspected will be in accordance with ASME IWF-2500-1. The staff's concerns described in RAIs B.1.24-1 and B.1.24-1a are resolved.

Enhancement 4. LRA Section B.1.24 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that the program will add the following as unacceptable conditions:

- loss of material due to corrosion or wear, which reduces the load-bearing capacity of the component support
- debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support
- cracked or sheared bolts, including high-strength bolts, and anchors

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 AMP consistent with the GALL Report recommendations to manage the applicable aging effects.

Summary. Based on its audit, and review of the applicant's responses to RAIs B.1.24-5 B.1.24-2, and B.1.24-3, 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.S3. In addition, the staff reviewed the enhancements associated with the "scope of program," and "parameters "acceptance criteria," program elements as well as one enhancement associated with the "detection of aging effects," program element and finds that when implemented, they will make the AMP consistent with the GALL Report recommendations to manage the applicable aging effects. In addition, the staff reviewed Enhancements 1–4 and finds them acceptable, as discussed above.

Operating Experience. LRA Section B.1.24 summarizes operating experience related to the Inservice Inspection – IWF Program. The applicant stated that results of ISI examinations for pipe hanger and supports for the RCIC system during RF16 in 2008 were acceptable. The applicant also stated that results of ISI examinations for component supports in the reactor recirculation system during RF17 in 2010 were acceptable.

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 AMP 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's onsite review indicated that there may be age-related degradation of underwater bolting of component supports and bolting in the SSW basins. During the audit, the applicant stated that the degraded bolting was not found during IWF inspections and is thus not subject to IWF requirements for expansion of scope per ASME Section IWF-2430. In all cases, the applicant entered the conditions into the corrective action process. The staff noted that although these were not IWF inspections, it is possible that bolts that are within the scope of the IWF Program may have been identified as degraded during these inspections. The staff determined that it needed additional information to complete its review. Therefore, by letter dated May 9, 2012, the staff issued RAI B.1.24-4 requesting that the applicant provide information as to whether any evaluation that was performed to determine if any of the degraded bolts found in the SSW basin are part of the IWF sample. The staff also requested that the applicant state whether it plans to do any additional examinations of component supports. Finally, the staff requested that the applicant provide information on whether the latest ISI IWF inspection conducted in July 2011 included any bolts in the SSW basins and the results of the inspection of those bolts.

The applicant responded by letter dated June 6, 2012. The applicant stated that there are a number of IWF supports in the SSW basin and the sample population for the ISI-IWF inspection included the identified deficient component supports. The applicant also stated that, during the July 2011 inspection of the SSW basin, a hanger was found degraded and the applicant performed an evaluation in accordance with ASME IWF-3112.3 to accept the component as-is in its degraded state. The applicant reworked the component and replaced degraded bolting and stated that the IWF Program includes provisions to re-inspect the degraded support during the next inspection period in accordance with ASME IWF-2420. The applicant finally stated that examinations performed on the remaining population of supports found no degraded bolting that failed to meet acceptance criteria.

The staff noted in its review of the applicant's response to RAI B.1.24-2 that because of the identified degradation the applicant has expanded the scope of inspection of the SSW basin to 100 percent of the underwater supports. The staff also noted that the applicant's response to RAI B.1.24-2a stated that there are no other areas subject to the same age-related degradation of this material and environment combination in the IWF program. Therefore, the staff finds the applicant's response acceptable because it appropriately applied the provisions of the ASME IWF Code for expansion of scope and frequency of inspection due to discovery of a degraded condition. The staff's concern described in RAI B.1.24-2 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.1.24-4, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.24 provides the UFSAR supplement for the Inservice Inspection – 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 finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's ISI-IWF, 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 through Commitment No. 14 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.24 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.25 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 of cranes and hoists, based on applicable industry standards and guidance documents. The activities rely on visual examinations and functional testing to ensure that cranes and hoists are capable of sustaining their rated loads. The program implements the guidance provided in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," issued July 1980.

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 seven 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" 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.1.25 states an enhancement to the "scope of program" program element. In this enhancement, the LRA states that the program will be enhanced to include monitoring of rails in the rail system for the aging effect of wear and structural connections and bolting for loose or missing bolts, nuts, pins, or rivets. Additionally, the program will be clarified to include visual inspection of structural components and structural bolts for loss of material due to various mechanisms and structural bolting for loss of preload due to self-loosening. GALL Report AMP XI.M23 recommends that the bridge, bridge rails, and trolley structural components be visually inspected for loss of material due to corrosion; rails be visually inspected for loss of material due to wear; and bolted connections 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 2. LRA Section B.1.25 states an enhancement to the "acceptance criteria" program element. In this enhancement, the LRA states that the program will be revised to state that any significant loss of material for structural components and structural bolts, and significant wear of rails in the rail system, is evaluated in accordance with ASME B30.2 or other applicable industry standard in the ASME B30 series. GALL Report AMP XI.M23 recommends that crane rails and structural components be visually inspected for loss of material due to 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 and that any indication of loss of material or loss of preload be evaluated in accordance with ASME B30.2 or other applicable industry standard in the ASME B30 series. 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 ensure any indication of aging is evaluated in accordance with the ASME B30 series standards to make the program consistent with the recommendations in the GALL Report AMP.

Summary. Based on its audit, and review of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, the staff finds that program elements one through six 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" 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.1.25 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 during a turbine building crane inspection, the bridge girder junction bolts, the bridge cross tie bolts, and the bridge drive coupling bolts were found to be loose. The LRA states that corrective actions were taken to tighten all of the bolting. During the audit, the staff reviewed this operating experience example and noted that no additional loose bolts have been discovered on the turbine building crane since the repair was completed. In another operating experience example, the LRA states that during an inspection of the polar crane rail clips, a broken stud was found at azimuth 90. The rail clips were replaced and further analysis was completed to confirm that the broken stud was a result of inadvertent impact, as opposed to an aging issue.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.25 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 applicant committed (Commitment No. 15) to enhance the program prior to May 1, 2024, to revise the acceptance criteria to be consistent with the ASME B30 series standards and to include monitoring of rails in the rail system for the aging effect of wear and structural connections and bolting for loose or missing bolts, nuts, pins, or rivets. Additionally, the program will be clarified to include visual inspection of structural components and structural bolts for loss of material due to various mechanisms and structural bolting for loss of preload due to self-loosening. 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 applicant's 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 through Commitment No. 15 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.25 Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B.1.26 describes the new 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," as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." The LRA states that the AMP includes opportunistic visual inspections of internal surfaces of piping and components, performed during periodic surveillances or maintenance activities when the surfaces are made accessible, to manage the effects of aging within the program. As modified in its response dated May 13, 2014, the program includes an assessment of the opportunistic inspections every 10 years during the period of extended operation for each combination of material, environment, and aging effect to ensure a representative sample of components is inspected. Metallic components will be managed for loss of material and fouling. Elastomeric components will be managed for cracking and change in material properties. The LRA also states that visual examinations will be accompanied by physical manipulation or pressurization to detect changes in material properties for elastomeric components within the program.

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.M38. For the program description and "scope of program," "parameters monitored or inspected," "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 program description for GALL Report AMP XI.M38 states that the program includes internal inspections of metallic ducting. The program description also states that the program includes components exposed to air-indoor uncontrolled, air outdoor, condensation and water systems other than fire water, open-cycle cooling water, and closed treated water systems. However, the applicant's description of its Internal Surfaces in Miscellaneous Piping and Ducting Components Program does not discuss whether metallic ducting will be included in the program or the environments covered by the program. By letter dated April 12, 2012, the staff issued RAI B.1.26-1 requesting that the applicant clarify if metallic ducting is included in the program and to describe the environments covered by the program.

In its response dated May 9, 2012, the applicant stated that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is consistent with GALL Report AMP XI.M38, without exception, and that the components and environments covered by the program are listed in the AMR items. The applicant revised the UFSAR supplement in LRA Section A.1.26 to clarify that metallic ducting is managed by the program. However, the applicant did not revise LRA Section A.1.26 to describe the environments managed by the program. The staff's concern regarding the UFSAR supplement is associated with RAI B.1.26-1a, which is discussed in the UFSAR supplement section of the staff's evaluation of this program. The staff finds the applicant's response acceptable because metallic ducting is included within the scope of the program, which is consistent with GALL Report AMP XI.M38 and the environments listed in the AMR items for the components managed by this program are consistent with the environments managed by GALL Report AMP XI.M38. The staff's concerns described in RAI B.1.26-1 regarding the program description are resolved. RAI B.1.26-1 also addresses concerns with the "detection of aging effects" program element, which is discussed later in this section.

The "scope of program" program element of GALL Report AMP XI.M38 states that the program manages the aging effects of hardening, loss of strength, cracking, and loss of material for polymeric and elastomeric components. GALL Report AMP XI.M38 also states that metallic components are managed for the aging effect of loss of material. The applicant also applies the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage fouling for metallic components. The staff issued RAIs B.1.26-2, B.1.26-3, and B.1.26-4, as discussed below, regarding the "scope of program" program element.

LRA Table 3.3.2-16 includes an AMR item for copper alloy with greater than 15 percent zinc (inhibited) heat exchanger tubes exposed to air-indoor (external) that are not being managed for reduction of heat transfer. By letter dated April 12, 2012, the staff issued RAI B.1.26-2 requesting that the applicant justify why LRA Table 3.3.2-16 does not include an AMR item for copper alloy with greater than 15 percent zinc (inhibited) heat exchanger tubes exposed to air-indoor (external) with an intended function of heat transfer. In its response dated May 9, 2012, the applicant stated that the heat exchanger tubes do not have a heat transfer function because they are covered by aluminum fins and that the aluminum fins have a heat transfer function that is being managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff reviewed the applicant's response and finds it acceptable because the heat exchanger tubes do not have a heat transfer function and therefore do not need to be managed for reduction of heat transfer, and the aluminum fins, which do have a heat transfer function, are being managed for fouling using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff's concern described above in RAI B.1.26-2 is resolved.

The LRA states that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages hardening and loss of strength for elastomers and polymers. However, the elastomer AMR items in the LRA that credit the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage aging, state that they are being managed for change in material properties and cracking. By letter dated April 12, 2012, the staff issued RAI B.1.26-3 requesting that the applicant include all of the aging effects managed by the program and to provide justification for any aging effects that are not consistent with those listed in GALL Report AMP XI.M38. In its response, dated May 9, 2012, the applicant stated that the program will manage change in material properties and cracking for elastomeric components because hardening and loss of strength are examples of changes in material properties and can result in cracking of elastomers. The applicant also stated that metallic components will be managed for loss of material and fouling. The staff reviewed the applicant's response and finds it acceptable because the program will manage loss of material and fouling for metallic components and cracking and change in material properties for elastomers, which is consistent with the recommendations in GALL Report AMP XI.M38. The staff's concern described in RAI B.1.26-3 is resolved.

LRA Table 3.2.1, item 3.2.1-43 states that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages hardening and loss of strength for elastomer seals and components exposed to air-indoor (internal). However, LRA Table 3.2.2-6 states that duct flexible connections and elastomers exposed to air-indoor (internal) will be managed for cracking and change in material properties. By letter dated April 12, 2012, the staff issued RAI B.1.26-4 requesting that the applicant justify why the aging effects of hardening and loss of strength discussed in LRA Table 3.2.1, item 3.2.1-43 are reflected as cracking and change in material properties aging effects in LRA Table 3.3.2-6. In its response dated May 9, 2012, the applicant stated that the program will manage change in material properties and cracking for these components as these are aging effects reflective of hardening and loss of strength. The staff reviewed the applicant's response and finds it acceptable because the program will manage cracking and change in material properties for elastomers, which is consistent with the recommendations in GALL Report AMP XI.M38. The staff's concern described in RAI B.1.26-4 is resolved.

The "parameters monitored or inspected" program element in GALL Report AMP XI.M38 recommends that the inspection parameters for metallic components include surface discontinuities, such as corrosion and material parameters wastage, leakage from or onto internal surfaces, and worn, flaking or oxide-coated surfaces. GALL Report AMP XI.M38 also recommends that the inspection parameters for polymers include surface cracking, crazing, scuffing, dimensional change, discoloration, exposure of internal reinforcement for reinforced elastomers, and hardening as evidenced by a loss of suppleness during manipulation. However, LRA Section B.1.26 does not provide a description of the inspection parameters that the program will use to identify aging for metallic components and polymers. By letter dated April 12, 2012, the staff issued RAI B.1.26-5 requesting that the applicant justify why the program does not include the parameters monitored and their related aging effects or amend the LRA to include this information.

In its response dated May 9, 2012, the applicant revised LRA Section B.1.26 to state that elastomeric components will be visually inspected for cracking and changes in material properties, including surface discontinuities, and metallic components will be visually inspected for surface conditions indicative of loss of material. The staff finds the applicant's response acceptable because the program now includes inspection parameters for metallic and elastomeric components consistent with the recommendations in the GALL Report. The staff's concern described in RAI B.1.26-5 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.M38 states that the program's inspections are opportunistic, applied when surfaces become accessible during the performance of periodic surveillances, maintenance activities or scheduled outages, and that if visual inspections of internal surfaces are not possible, then a plant-specific program should be developed. GALL Report AMP XI.M38 also recommends that the available surface area for physical manipulation of flexible polymeric components be at least 10 percent. However, LRA Sections A.1.26 and B.1.26 do not describe if the program is opportunistic or if there are internal surfaces that are not accessible, and does not state the available surface area to be used with physical manipulation. The staff issued RAIs B.1.26-1 and B.1.26-8, discussed below, regarding the "detection of aging effects" program element.

By letter dated April 12, 2012, the staff issued RAI B.1.26-1 requesting that the applicant identify if the program is opportunistic and what the available surface area is that will be used with physical manipulation. In its response dated May 9, 2012, the applicant stated that the program is opportunistically applied whenever the components are opened for any reason and that the sample size for manipulation of flexible polymeric components is at least 10 percent of the available surface area. The staff finds the applicant's response acceptable because the program is opportunistically applied and the sample size for physical manipulation of elastomeric components is at least 10 percent of the available surface area, which is consistent with the GALL Report recommendations. The staff's concern described in RAI B.1.26-1 regarding the "detection of aging effects" program element is resolved.

By letter dated April 12, 2012, the staff issued RAI B.1.26-8 requesting that the applicant identify if any of the program's components are inaccessible. In its response dated May 9, 2012, the applicant stated that the program has no inaccessible components. The staff finds the applicant's response acceptable because the program does not include any inaccessible components; therefore, a plant-specific program is not recommended by the GALL Report. The staff's concern described in RAI B.1.26-8 is resolved.

The "acceptance criteria," program element in GALL Report AMP XI.M38 states acceptance criteria for the metallic and polymeric (both rigid and flexible) components in the program. However, LRA Section B.1.26 does not describe the program's acceptance criteria. By letter dated April 12, 2012, the staff issued RAI B.1.26-6 requesting that the applicant amend LRA

Section B.1.26 to include the acceptance criteria for this program. In its response dated May 9, 2012, the applicant revised LRA Section B.1.26 to include the following acceptance criteria:

- stainless steel: clean surfaces, shiny, no abnormal surface conditions
- metals: no abnormal surface condition
- flexible polymers: a uniform surface texture and color with no cracks, no unanticipated dimensional change, and no abnormal surface conditions
- rigid polymers: no surface changes affecting performance such as erosion and cracking

The staff finds the applicant's response acceptable because the program includes acceptance criteria against which the need for corrective actions can be evaluated to ensure that the component's intended functions are maintained consistent with the GALL Report recommendations. The staff's concern described in RAI B.1.26-6 is resolved.

Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," which revises several GALL Report AMPs including the guidance for AMP XI. M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." By letter dated January 2, 2014, the staff issued RAI 3.0.3-1, noting that the applicant may not have incorporated the updated guidance, and requesting that the applicant provide information on how the updated guidance of LR-ISG-2012-02 has been accounted for in its AMPs. In its response dated May 13, 2014, the applicant revised LRA Sections A.1.26 and B.1.26 for the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to state that an assessment will be made of the opportunistic visual inspections completed during each 10-year period to ensure a representative sample is inspected. Directed inspections will be conducted to ensure that a sample size of 20 percent with a maximum of 25 inspections for each combination of material, environment, and aging effect during each 10-year period of extended operation. The applicant also stated that, where practical, inspections will be conducted at locations that are most susceptible to the effects of aging.

The staff finds the applicant's response acceptable because the representative minimum sample size is consistent with the guidance in the GALL Report. The staff's concern relating to this AMP in RAI 3.0.3-1 is resolved.

Based on its audit and review of the applicant's responses to RAIs B.1.26-1, B.1.26-2, B.1.26-3, B.1.26-4, B.1.26-5, B.1.26-6, B.1.26-8, and 3.0.3-1 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.M38.

Operating Experience. LRA Section B.1.26 summarizes operating experience related to the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The LRA states that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program for which program-specific operating experience will be gained as the program is implemented, but that the elements of the inspections used in this program are consistent with industry practice. The LRA also states that the inspection techniques that will be used as part of the Internal Surfaces in Miscellaneous Piping and Ducting Components Program have been proven effective at identifying aging effects in other existing site programs. During the audit, the staff reviewed operating experience examples where internal inspections were performed on motors and sparger end caps in which aging effects were identified before loss of the component's intended function.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, industry, and plant-specific operating experience were reviewed by the applicant. As discussed in the AMP 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 industry and plant-specific operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.26 provides the UFSAR supplement for the Internal Surfaces in Miscellaneous Piping and Ducting Components 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 LRA UFSAR supplement description does not include a complete description of the components, environments, aging effects, and systems included in the program; does not discuss how the program intends to retain a component's intended function; and does not include a provision to use a plant-specific program when visual inspections of internal surfaces are not possible. 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 April 12, 2012, the staff issued RAIs B.1.26-1 and B.1.26-7 requesting that the applicant include key elements of the program in the UFSAR supplement consistent with the description for this program in SRP-LR Table 3.0-1. In its response dated May 9, 2012, the applicant revised LRA Sections A.1.26 and B.1.26 to state that the program includes metallic ducting, the aging effects of loss of material, fouling, cracking, and change in material properties; that the program's inspections will be opportunistic; and that there are no inaccessible components in the program. However, the applicant did not revise the UFSAR supplement to include a description of the environments managed by the program.

The staff reviewed the applicant's response and found it unacceptable because there is no description in the applicant's revised UFSAR supplement of the environments managed by the program. By letter dated July 17, 2012, the staff issued RAI B.1.26-1a requesting that the applicant amend LRA Section A.1.26 to fully describe the program's applicable environments, consistent with the minimum UFSAR supplement description for this program found in the SRP-LR, Table 3.0-1.

In its response dated August 13, 2012, the applicant stated that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is consistent with GALL Report AMP XI.M38, without exception; therefore, the environments described in the UFSAR supplement are consistent with those in GALL Report AMP XI.M38. The applicant revised the UFSAR supplement in LRA Section A.1.25 to clarify that the program manages the effects of aging for piping and components exposed to environments of air-indoor, air-outdoor, condensation, exhaust gas, lube oil, raw water, waste water, and treated water. The staff finds the applicant's response acceptable because the UFSAR supplement in LRA Section A.1.25 has been revised to include the environments within the scope of the program, which are also consistent with the environments listed in GALL Report AMP XI.M38. The staff's concerns described in RAI B.1.26-1a are resolved.

As amended by letter dated October 25, 2013, the applicant revised the UFSAR supplement to include a reference to plastic components in conjunction with the statement that elastomeric components will be visually inspected to detect potential cracking and change in material properties. The staff finds this change acceptable because the use of visual inspections to detect cracking and change in material properties is consistent with the "parameters monitored/inspected" program element of GALL Report AMP XI.M38.

In its response dated May 13, 2014, the applicant also revised the UFSAR supplement to include a representative minimum sample size for the visual inspections being performed. During each 10-year period of extended operation, the applicant will ensure that inspections are conducted on a sample of 20 percent, up to a maximum of 25, for each combination of material, environment, and aging effect. The staff finds the applicant's revised UFSAR supplement to be consistent with the corresponding program description in SRP-LR Table 3.0-1, as modified by LR-ISG-2012-02.

The staff also noted that the applicant committed by letter dated October 28, 2011, (Commitment No. 16) to implement the new Internal Surfaces in Miscellaneous Piping and Ducting program prior to 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 May 13, 2014, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components, 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.M38. 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).

3.0.3.1.26 Masonry Wall

Summary of Technical Information in the Application. LRA Section B.1.27 describes the existing Masonry Wall Program as consistent with enhancements with GALL Report AMP XI.S5, "Masonry Walls." The LRA states that the AMP proposes to manage aging effects, for masonry walls within the scope of license renewal, including 10 CFR 50.48-required masonry walls, radiation-shielding walls, and masonry walls with the potential to affect safety-related components. The LRA also states that structural steel components are managed by the Structures Monitoring Program, and that masonry walls are visually inspected at a frequency selected to ensure there is no loss of intended function between inspections.

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.S5. 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.S5 recommends inspection of masonry walls every 5 years, with provisions for more frequent inspections in areas where significant loss of material or cracking is observed to ensure there is no loss of intended function between inspections. However, during its audit, the staff found that the applicant’s Masonry Wall Program, when enhanced, proposes to inspect masonry walls every 5 years, unless technical justification is provided to extend the inspection to a period not to exceed 10 years. By letter dated May 3, 2012, the staff issued RAI B.1.27-1 requesting that the applicant clarify whether masonry walls will be inspected every 5 years, and if not, to identify their location, environment to which they are exposed, and provide the technical justification and basis for exceeding the recommended 5-year inspection frequency.

In its response dated May 30, 2012, the applicant stated that the masonry walls within the scope of license renewal will be inspected every 5 years, and the enhancement identified in LRA Section B.1.27 Element 4, “detection of aging effects,” will be revised to remove the provision to extend the inspection interval up to 10 years.

The staff finds the applicant’s response acceptable because the revision to the “detection of aging effects” enhancement removes the provision for the applicant to extend the inspection interval to a period not to exceed 10 years. The enhancement now clearly indicates that masonry walls within the scope of license renewal will be inspected every 5 years, consistent with the recommendations in GALL Report AMP XI.S5. The staff also noted that, during its review of the masonry wall AMRs, those walls that are also fire barriers are visually inspected using the Fire Protection Program consistent with the recommendations in the GALL Report. The staff’s concern described in RAI B.1.27-1 is resolved.

The staff also reviewed the portions of the “parameters monitored or inspected” and “detection of aging effects” 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.1.27 states an enhancement to the “parameters monitored or inspected” program element. In this enhancement, the applicant stated that the Masonry Wall Program will be enhanced to clarify that parameters monitored or inspected will include monitoring gaps between the supports and masonry walls that could potentially affect wall qualification. 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 make the program consistent with the GALL Report AMP.

Enhancement 2. LRA Section B.1.27 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the Masonry Wall Program will be enhanced to clarify that detection of aging effects requires masonry walls to be inspected every 5 years unless technical justification is provided to extend the inspection to a period not to exceed 10 years. However, in response to RAI B.1.27-1, the applicant revised this enhancement to remove the provision for extending the inspection to a 10-year interval and clarify that masonry walls within the scope of license renewal will be inspected every 5 years. The staff reviewed the revised enhancement against the corresponding program elements in GALL Report AMP XI.S5, noted that the masonry walls that are fire barriers are also visually inspected by the Fire Protection Program, and finds it acceptable because, when it is implemented, it will make the program consistent with GALL Report AMP XI.S5.

Summary. Based on its audit, and review of the applicant's response to RAI B.1.27-1 of the applicant's Masonry Wall Program, the staff finds that program elements one through six 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 "parameters monitored or inspected" and "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.1.27 summarizes operating experience related to the Masonry Wall Program. The applicant stated that program assessments covering the period from 2001 to 2007 identified no problems with masonry walls and concluded the structure inspection program is adequate and effective. The applicant also stated that reviews against established program standards provide assurance that the program will remain effective for managing loss of material of components. Furthermore, the applicant will consider future plant-specific operating experience per LRA Section B.0.4.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.27 provides the UFSAR supplement for the Masonry Wall 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 applicant committed (Commitment No. 17) to enhance the Masonry Wall Program prior to the period of extended operation to:

- clarify that parameters monitored or inspected will include monitoring gaps between the supports and masonry walls that could potentially affect wall qualification
- clarify that detection of aging effects require masonry walls to be inspected every 5 years

The staff finds that the information in the UFSAR supplement, as amended by letter dated July 3, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Masonry Wall 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 through Commitment No. 17 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.27 Non-EQ Cable Connections

Summary of Technical Information in the Application. LRA Section B.1.28 describes the new Non-EQ Cable Connections 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 Non-EQ Cable Connections Program is a one-time inspection program that provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections are maintained consistent with the CLB through the period of extended operation. The applicant also stated that cable connections included are those connections susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the EQ requirements of 10 CFR 50.49. The applicant further stated that this program provides for one-time inspections that will be completed prior to the period of extended operation on a sample of connections.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report AMP XI.E6. For the "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 RAIs, as discussed below.

The "parameters monitored or inspected" program element in GALL Report AMP XI.E6 recommends that the following factors are considered for sampling: voltage level (medium and low voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). Most connections used in nuclear power plants include splices (butt or bolted), crimp-type ring lugs, connectors, and terminal blocks. However, during its audit, the staff found that the applicant's program basis document, GGNS-EP-08-LRD08, Revision 1, states that the representative sample of electrical cable connections will be tested, and the factors considered for sample selection will be application (medium and low voltage), circuit loading (high voltage), and location (high temperature, high humidity, vibration, etc.). The "parameters monitored or inspected" program element of the applicant's basis document GGNS-EP-08-LRD08, Revision 1, does not consider or address connection types in the sample selection criteria. By letter dated April 30, 2012, the staff issued RAI B.1.28-1 requesting that the applicant clarify how the Non-EQ Cable Connections Program is consistent with GALL Report AMP XI.E6 with respect to sample selection criteria including connection type.

In its response dated May 25, 2012, the applicant stated that as stated in LRA Section B.1.28, the GGNS Non-EQ Cable Connections Program is consistent with the program described in the GALL Report AMP XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, without exception. In addition, the applicant stated that LRA Section B.1.28 states, "The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kilovolts (kV)), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.)." Therefore, connection type is a factor that will be considered in sample selection. The staff found the applicant's response unacceptable because the applicant has not revised the basis document. The basis document under "parameters monitored or inspected" program element was not consistent with those in GALL Report AMP XI.E6 because it did not consider connection types as part of the sampling basis. In a letter dated July 17, 2012, the staff requested the applicant to revise the basis document to include connection type as part of the sampling basis or explain how the "parameters monitored or inspection" program element is consistent with those in GALL Report AMP XI.E6. In response to the staff's request, in a letter dated August 13, 2012, the applicant stated that the GGNS AMP evaluation report (basis document) for the Non-EQ Cable Connections Program was revised to indicate that connection type will be included in the sample selection. The staff found the applicant's response acceptable because the applicant changed the basis document to include connection type as a factor in sample selection. The selection sample criteria are consistent with those in GALL Report AMP XI.E6. The staff's concern in RAI B.1.28-1 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.E6 recommends that testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation, such as heat shrink tape, sleeving, insulation boots, etc. However, during its audit, the staff found that the applicant's program basis document, GGNS-EP-08-LRD08, for the same program element states that inspection methods may include thermography, contact resistance testing, or other appropriate quantitative methods based on plant configuration and industry guidance. Based on the program description in the program basis document, it appears that the applicant may be using other quantitative methods that may include removing the connection insulation. By letter dated April 30, 2012, the staff issued RAI B.1.28-2 requesting the applicant to clarify if there are other appropriate quantitative methods, which may include removing connection insulation that will be used at GGNS. If there are other methods, the staff requested the applicant to justify why this practice is consistent with the recommendations in GALL Report AMP XI.E6.

In its response dated May 25, 2012, the applicant stated that the AMP evaluation report for the GGNS Non-EQ Cable Connections Program (GGNS-EP-08-LRD08) statement for "Detection of Aging Effects" will be clarified to state that, "[i]nspection methods may include thermography, contact resistance testing, or other appropriate quantitative test methods without removing the connection insulation such as heat shrink tape, sleeving, insulating boots, etc., based on plant configuration and industry guidance."

The staff finds the applicant response acceptable because, if the applicant uses other testing methods besides thermography and contact resistance, it will not remove the connection insulation such as heat shrink tape, sleeving, insulation boots, etc. This practice is consistent with the recommendation from GALL Report AMP XI.E6. The staff's concern described in RAI B.1.28-2 is resolved.

Based on its audit, and review of the applicant's responses to RAIs B.1.28-1 and B.1.28-2, of the applicant's Non-EQ Cable Connections Program, the staff finds that program elements one through six for which the applicant claimed consistency with GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E6.

Operating Experience. LRA Section B.1.28 summarizes operating experience related to the Non-EQ Cable Connections Program. The applicant stated that the Non-EQ Cable Connections Program is a new program. Industry operating experience was considered in the development of this program. The applicant also stated that plant operating experience will be gained as the program is implemented and will be factored into the program through the confirmation and corrective action elements of the GGNS 10 CFR Part 50, Appendix B, quality assurance program. The applicant stated that this inspection program applies to potential aging effects for which there is currently no operating experience at GGNS indicating the need for an AMP. The applicant further stated that elements of the program inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and have been used effectively at GGNS in other programs.

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 AMP 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. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.28 provides the UFSAR supplement for the Non-EQ Cable Connections 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 in SRP-LR Table 3.0.1, UFSAR supplement for Aging Management of Applicable Systems, under GALL Report AMP XI.E6, recommends that the program consists of a representative sample of electrical connections within the scope of license renewal, which is tested at least once before the period of extended operation to confirm that there are no AERM during that period. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc. In the LRA Appendix A.1.28, the applicant stated that the Non-EQ Cable Connection Program is a one-time inspection program that provides reasonable assurance that the intended function of the metallic parts of electrical connections are maintained with the CLB through the period of extended operation. It further states that cable connections included are those connections susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the EQ requirements of 10 CFR 50.49. This program provides for a one-time quantitative inspection that will be completed before the period of extended operation on a sample of connections. In this LRA, the applicant stated that the program is consistent with GALL Report AMP XI.E6. However, the UFSAR supplement description does not describe the type of test it will perform. The licensing basis for this program may not be adequate if the applicant does not incorporate this information into its UFSAR supplement. By letter dated April 30, 2012, the staff issued RAI B.1.28-3, requesting that the applicant justify why the UFSAR supplement description does not describe the type of testing that may be performed, consistent with that in SRP-LR Table 3.0-1 for GALL Report AMP XI.E6.

In its response dated May 25, 2012, the applicant stated that the type of testing is described in the AMP evaluation report for the GGNS Non-EQ Cable Connections Program. This description will be added to LRA Section A.1.28 as shown below.

> A.1.28 Non-EQ Cable Connections Program
>
> The Non-EQ Cable Connections Program is a one-time inspection program that provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections are maintained consistent with the current licensing basis through the period of extended operation. Cable connections included are those connections susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the environmental qualification requirements of 10 CFR 50.49.
>
> This program provides for one-time quantitative inspections that will be completed prior to the period of extended operation on a sample of connections. The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). The representative sample size will be based on twenty percent of the connection population with a maximum sample of 25.
>
> Inspection methods may include thermography, contact resistance testing, or other appropriate quantitative test methods without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc., based on plant configuration and industry guidance.
>
> This program will be completed prior to the period of extended operation.

The staff finds the applicant's response acceptable because the applicant describes the testing methods in the UFSAR supplement. The program description in UFSAR supplement for the Non-EQ Cable Connections Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.1.28-3 is resolved.

The staff also noted that the applicant committed (Commitment No. 18) to implement the new Non-EQ Cable Connections Program prior to 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.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Non-EQ Cable Connections 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).

3.0.3.1.28 Non-EQ Inaccessible Power Cables (400 V to 35 kV)

Summary of Technical Information in the Application. LRA Section B.1.29 describes the existing Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program as consistent, with enhancements, with GALL Report AMP XI.E3, "Inaccessible Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program includes periodic actions to prevent inaccessible cables from being exposed to significant moisture. The applicant also stated that cables exposed to significant moisture will be tested at least every 6 years with test frequencies adjusted based on test results and operating experience. In addition, the applicant stated that the program includes periodic inspections for water accumulation in manholes at least once every year and includes manhole inspections for water after events such as heavy rain or flooding. The applicant further stated that inspection frequencies will be increased as necessary based on evaluation of inspection results.

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.E3.

The staff also reviewed the portions of the "scope of program" and "preventive 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.1.29 includes an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program will be enhanced to include low-voltage (400 V to 2 kV) power cables. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E3 and finds it acceptable because when implemented it will provide consistency with GALL Report AMP XI.E3 "scope of program" program element which includes low-voltage inaccessible power cables (400 V to 2 kV) and SRP-LR Table 3.6-1.

Enhancement 2. LRA Section B.1.29 includes an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program will be enhanced to include condition-based inspections of manholes that are not automatically dewatered by sump pumps following periods of heavy rain or potentially high water table conditions, as indicated by river level.

In addition, the program will be clarified to state that manhole inspections will include direct observation that the cables are not wetted or submerged and that cable/splices and cable support structures are intact and include verification that dewatering/drainage systems (i.e., sump pumps) and associated alarms, if applicable, operate properly. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will provide consistency with GALL Report AMP XI.E3 "preventive actions" program element that includes confirmation that drainage systems operate properly. The enhancement is also consistent with SRP-LR Table 3.6-1.

Summary. Based on its audit of the applicant's Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E3. In addition, the staff reviewed the enhancements associated with the “scope of program” and “preventive 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.1.29 summarizes operating experience related to the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program. In the applicant’s response to GL 2007-01 (“Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients,” issued February 2007), dated May 4, 2007, the applicant stated that it had experienced one cable failure within the scope of the maintenance rule 10 CFR 50.65. The applicant identified the cable as service for the 480 V motor-driven fire pump and stated that the apparent cause of failure was age degradation attributed to moisture and possible damage during construction. The staff also reviewed several recent NRC inspection reports.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.29 provides the UFSAR supplement for the Non-EQ Inaccessible Power Cables (400 V to 35 kV) 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 applicant committed (Commitment No. 19) to enhance the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program to include low-voltage power cables (400 V to 2 kV) and to include condition-based inspections of manholes not automatically dewatered by a sump pump to be performed following periods of heavy rain or potentially high water table conditions, as indicated by river level. The program will also be enhanced to clarify that the inspections will include direct observation that the cables are not wetted or submerged and that cable/splices and cable support structures are intact and that dewatering/drainage (i.e., sump pumps) and associated alarms, if applicable, operate properly. The commitment is to be implemented prior to November 1, 2024.

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 applicant’s Non-EQ Inaccessible Power Cables (400 V to 35 kV) 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 through Commitment No. 19 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.29 Non-EQ Instrumentation Circuits Test Review

Summary of Technical Information in the Application. LRA Section B.1.30 describes the new Non-EQ Instrumentation Circuits Test Review 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 that the program assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation, and moisture can be maintained consistent with the CLB through 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 one through six of the applicant’s program to the corresponding program elements of GALL Report AMP XI.E2.

Based on its audit of the applicant’s Non-EQ Instrumentation Circuits Test Review Program, the staff finds that program elements one through six 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.1.30 summarizes operating experience related to the Non-EQ Instrumentation Circuits Test Review Program. The applicant stated that a search of GGNS operating experience identified no age-related failures of neutron monitoring and high range radiation monitoring system cables and connections at GGNS, and no aging mechanism not considered in the GALL Report has been identified. During its audit, the staff inquired about occurrence of local power range monitor spiking, which is common for Boiling Water Reactors. The staff noted that spiking events have occurred in the past and that the applicant took corrective actions by performing current-voltage characteristic tests in accordance with GE SIL 564, “Verification of SRM, IRM, or LPRM Detector Response.”

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 AMP 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. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.30 provides the UFSAR supplement for the Non-EQ Instrumentation Circuits Test Review 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 applicant committed (Commitment No. 20) to implement the new Non-EQ Instrumentation Circuits Test Review Program prior to 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 applicant's Non-EQ Instrumentation Circuits Test Review 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).

3.0.3.1.30 Non-EQ Insulated Cables and Connections

Summary of Technical Information in the Application. LRA Section B.1.31 describes the new Non-EQ Insulated Cables and Connections 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 a representative sample consisting of accessible insulated cables and connections within the scope of license renewal installed in an adverse localized environment will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, 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 one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.E1. 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.E1 recommends the AMP applies to accessible electrical cables and connections within the scope of license renewal that are located in adverse localized environments caused by temperature, radiation, or moisture. However, as described in the AMP Audit Report, during the staff's walkdown of cables from ESF transformer Nos. 11, 12, and 21, the staff observed cables in uncovered open trays that may be subject to ultraviolet radiation and moisture. It is not clear how the applicant's Non-EQ Insulated Cables and Connections Program will be used to manage the aging effects of reduced insulation resistance in this open-air environment. By letter dated April 30, 2012, the staff issued RAI B.1.31-1 requesting applicant to explain how these components will be age managed, during the period of extended operation.

In its response dated May 25, 2012, the applicant stated that the ESF transformer cables will be managed by the GGNS Non-EQ Insulated Cables and Connections Program. Based on the bounding approach, the scope of this program includes the engineered cable bus to the ESF transformers. The applicant further stated that these cables were specifically designed for the environment and application where they are used.

The staff finds the applicant's response acceptable because the ESF transformer cables will be managed by the GGNS Non-EQ Insulated Cables and Connections Program. The staff's concern described in RAI B.1.31-1 is resolved.

The "scope of program" program element in GALL Report AMP XI.E1 recommends the AMP applies to accessible electrical cables and connections within the scope of license renewal that are located in adverse localized environments caused by temperature, radiation, or moisture. An adverse localized environment exists based on the most limiting condition for temperature, radiation, or moisture for the insulation material of the electrical cables or connections. The "parameters monitored or inspected" program element in GALL Report AMP XI.E1 recommends that an adverse localized environment is a plant-specific condition; therefore the applicant should clearly define how this condition is determined. The parameters monitored or inspected" program element also recommends that the applicant should determine and inspect for adverse localized environments for each of the most limiting temperature, radiation, or moisture conditions for the accessible cables and connections that are within the scope of license renewal. The applicant's LRA states that Non-EQ Insulated Cables and Connections Program will be consistent with GALL Report AMP XI.E1. However, the LRA does not define how an adverse localized environment is determined or the limiting conditions to be applied. By letter dated April 30, 2012, the staff issued RAI B.1.31-2 requesting the applicant to describe how the Non-EQ Insulated Cables and Connections Program will identify an adverse localized environment or what limiting conditions for temperature, radiation, or moisture of insulation material of electrical cables and connections will be applied in the identification of an adverse localized environment.

In its response dated May 25, 2012, the applicant stated that the determination of an adverse localized environment will be based on the most limiting temperature, radiation, or moisture conditions for the cables and connection insulation material located within that plant space. The applicant also stated that LRA Section B.1.31 will be modified to include the following:

An adverse localized equipment environment is a plant-specific condition that will be determined based on a plant spaces approach. The plant spaces approach provides for a review of all buildings and rooms in the scope of license renewal to determine potential adverse localized environments. The determination of a potential adverse localized equipment environment will be based on the most limiting temperature, radiation, or moisture conditions for the cables and connection insulation located at GGNS. The evaluation of an adverse localized equipment environment will be based on the most limiting temperature, radiation, or moisture conditions for the cables and connection insulation material located within that plant space that has a potential adverse localized equipment environment.

The staff finds the applicant's response acceptable because the applicant will determine an adverse localized environment by identifying the most limiting temperature, radiation, or moisture conditions based on cables and connections insulation material. The staff's concern described in RAI B.1.31-2 is resolved.

Based on its audit, and review of the applicant's responses to RAIs B.1.31-1 and B.1.31-2 of the applicant's Non-EQ Insulated Cables and Connections Program, the staff finds that program elements one through six 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.2.1.31 summarizes operating experience related to the Non-EQ Insulated Cables and Connections Program. The applicant stated that cables for a nonsafety-related valve located in the feedwater (FW) heater room were found to have heat-related degradation. Though the valve has no license renewal-intended function, the issue was identified, and the cables were replaced and rerouted to prevent future degradation.

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 AMP 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 RAIs B.1.31-1 and B.1.31-2, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.31 provides the UFSAR supplement for the Non-EQ Insulated Cables and Connections 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 applicant committed (Commitment No. 21) to implement the new Non-EQ Insulated Cables and Connections Program prior to 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 applicant's Non-EQ Insulated Cables and Connections 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).

3.0.3.1.31 Oil Analysis

Summary of Technical Information in the Application. LRA Section B.1.32 describes the existing Oil Analysis Program as consistent, with enhancements, with GALL Report AMP XI.M39, "Lubricating Oil Analysis." The applicant stated that the program ensures that loss of material, cracking, and fouling do not occur by maintaining oil environments free of contaminants (e.g., water and particulates). The applicant stated that testing activities include sampling and analysis of lubricating oil.

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.M39.

The staff also 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.1.32 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the Oil Analysis Program will be enhanced to include piping and components within the main generator system (N41) with an internal environment of lube oil. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M39 and finds it acceptable because when it is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.M39.

Enhancement 2. LRA Section B.1.32 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the Oil Analysis Program will be enhanced to provide a formalized analysis technique for particulate counting. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M39 and finds it acceptable because when it is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.M39.

Summary. Based on its audit, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M39. 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, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.32 summarizes operating experience related to the Oil Analysis Program.

The applicant stated that the fire water diesel engine lubricating oil sample results for 2000 through 2010 were satisfactory. However, the applicant stated that both fire water diesels had samples with high particle count. This was attributed to faulty lab equipment, and samples were taken at more frequent intervals to track the conditions. The applicant stated that particle count level remained below the limit and was evaluated to be satisfactory for continued service.

The applicant stated that samples of crankcase oil from the HPCS diesel generator (Division III) taken between 2005 and 2010 revealed possible high metal count. The applicant continued to observe the sample test results to determine if high count was caused by metal wear particles or malfunction of lab equipment. The applicant stated that, from 2008 on, the samples were normal, indicating a malfunction of lab equipment in the earlier samples.

In 2007 the applicant stated that a sample of Division I diesel engine lubricating oil indicated trace amounts of moisture contamination. The oil viscosity and other parameters were within manufacturer specifications. The applicant stated that a contaminated sample tube was suspected to be the cause of the indication. A resample was performed with clean sampling apparatus to confirm that the previously used sample tube was contaminated.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and plant-specific and industry operating experience were reviewed by the applicant. As discussed in the AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.32 provides the UFSAR supplement for the 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.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Oil Analysis 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 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.32 One-Time Inspection

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.33 describes the new One-Time Inspection Program as consistent with GALL Report AMP XI.M32, "One-Time Inspection." The LRA states that the AMP verifies the effectiveness of the Diesel Fuel Monitoring, Oil Analysis, and Water Chemistry Control programs to prevent or minimize aging effects of loss of material, cracking, and fouling to assure that loss of intended functions will not occur during the period of extended operation. The LRA also states that the AMP will provide additional confirmation to verify the insignificance of aging effects. The LRA further states that a sample size of components based on an assessment of the material, environment, aging effects, and operating experience will be used in the program and that examination techniques will utilize established non-destructive examination techniques.

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.M32. 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.M32 recommends that the program state what inspection method will be associated with each aging effect, aging mechanism, and parameter monitored. However, during its audit, the staff noted that the applicant's One-Time Inspection Program does not state what inspection methods are aligned with the aging effects of loss of material, cracking and fouling. By letter dated April 11, 2012, the staff issued RAI B.1.33-1 requesting that the applicant revise LRA Section B.1.33 to identify what inspection methods will be used in conjunction with each aging effect being managed by the program.

In its response dated May 9, 2012, the applicant revised the program description section of LRA Section B.1.33 to add a table that identifies the inspection methods associated with the aging effects for the program. The staff finds the applicant's response acceptable because the inspection methods associated with the aging effects are now fully described, are consistent with those in GALL Report AMP XI.M32, and the inspection methods and techniques are adequate to identify and manage the aging effects associated with this program. The staff's concern described in RAI B.1.33-1 is resolved.

Based on its audit and review of the applicant's One-Time Inspection Program and review of the applicant's response to RAI B.1.33-1, the staff finds that the program elements one through six 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.1.33 summarizes operating experience related to the One-Time Inspection Program. The LRA states that the One-Time Inspection Program is a new program for which program-specific operating experience will be gained as the program is implemented, but that the elements of the inspections used in this program are consistent with industry practice. The LRA also states that the inspection techniques that will be used as part of the One-Time Inspection Program have been proven effective at identifying aging effects in other existing site programs. During the audit, the staff reviewed operating experience examples where visual inspections had been completed on condenser bay ventilation components and snubbers in which aging effects were identified prior to loss of the component's 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 AMP 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. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.33 provides the UFSAR supplement for the One-Time Inspection 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 SRP-LR states that this program should not be used for structures or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. However, LRA Section A.1.33 does not state the conditions for which SCs will be excluded from the scope of the AMP. 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 April 11, 2012, the staff issued RAI B.1.33-2 requesting that the applicant revise the UFSAR supplement to fully describe this program consistent with the recommendations in the SRP-LR.

In its response dated May 9, 2012, the applicant revised LRA Section A.1.33 to state that the program cannot be used for structures or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. The staff finds the applicant's response acceptable because the UFSAR supplement has been revised to describe what structures or components cannot be age managed by the program consistent with the recommended description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.1.33-2 is resolved.

The staff also noted that the applicant committed (Commitment No. 23) to implement the new One-Time Inspection Program as described in LRA Section B.1.33 within the 10 years prior to entering the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by letter dated May 9, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection Program, the staff concludes that the 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).

3.0.3.1.33 One-Time Inspection – Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B.1.34 describes the new One-Time Inspection – 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 the program augments the requirements of ASME Code, Section XI, and applies to small-bore ASME Code Class 1 piping and components with a nominal pipe size (NPS) diameter less than 4 inches and greater than or equal to 1 inch in systems that have not experienced cracking of ASME Code Class 1 small-bore piping. The LRA also states that GGNS has not experienced cracking in this kind of piping due to stress corrosion, cyclical loading (including thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence. The program provides for a one-time volumetric inspection of a sample of locations that are susceptible to cracking, and this inspection will be performed within the 6-year period prior to the period of extended operation. The sample selection is based on susceptibility to stress corrosion, cyclic loading, or thermal stratification and thermal turbulence. In addition, the LRA states that if evidence of cracking is revealed by the one-time inspection, then a follow-up periodic inspection will be implemented through a plant-specific program.

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.M35. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M35 recommends an inspection sample size that is at least 3 percent of the weld population, or a maximum of 10 welds of each weld type, if the unit (a) has never experienced a failure of its ASME Code Class 1 small-bore piping and (b) has more than 30 years of operating history at the time when the application is submitted. Otherwise, the inspection sample size should be at least 10 percent of the weld population or a maximum of 25 welds of each weld type. The NRC issued the operating license for GGNS on November 1, 1984, and the applicant submitted the LRA on October 28, 2011; therefore, GGNS had less than 27 years of operating history at the time when the application was submitted. Based on the operating history of GGNS, the sample size for the one-time inspection should be at least 10 percent of the weld population or a maximum of 25 welds of each weld type to be consistent with GALL Report AMP XI.M35.

During its audit, the staff found that the applicant's One-Time Inspection – Small-Bore Piping Program does not indicate the total population of welds of each weld type or the total number of these welds that will be included in the volumetric inspections. By letter dated April 18, 2012, the staff issued RAI B.1.34-1 requesting that the applicant characterize the inspection sample size by providing the total number of ASME Code Class 1 small-bore piping (1) full penetration or butt welds and (2) partial penetration or socket welds at GGNS and the total number of these welds that will be included in the inspection sample. The staff also requested the applicant to provide technical justification if the sample size is less than the sample size described in the GALL Report (i.e., 10 percent of the weld population or a maximum of 25 welds of each weld type).

In its response dated May 18, 2012, the applicant stated that, because the One-Time Inspection – Small-Bore Piping Program is a new program, the total number of welds that will be included in the volumetric inspections, based on the total population of welds of each weld type, had not been determined. The applicant stated that it would provide this information at a later date and did so in a letter dated August 23, 2012. In this letter the applicant stated that, under the One-Time Inspection – Small-Bore Piping program, 20 butt welds will be inspected, which represents over 10 percent of the total number of ASME Code Class 1 small-bore piping butt welds in the plant. In addition, 25 socket welds will be inspected under the program, which is the maximum number of ASME Code Class 1 small-bore piping socket welds to be inspected consistent with GALL Report AMP XI.M35. The staff reviewed the applicant's response and finds it acceptable because the total number of small-bore butt and socket welds that will be inspected under the applicant's program is consistent the inspection sample size described in GALL Report AMP XI.M35, given the operating history of the plant. The staff's concern described in RAI B.1.34-1 is resolved.

The “detection of aging effects” program element in GALL Report AMP XI.M35 states that the program does not apply to plants that have experienced cracking in ASME Code Class 1 small-bore piping due to stress corrosion, cyclical loading (including thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence. LRA Section B.1.34 states that GGNS has not experienced this type of cracking; however, during its audit, the staff could not determine how or to what extent the applicant reviewed plant-specific operating experience information to demonstrate that GGNS has not experienced age-related cracking in ASME Code Class 1 small-bore piping. By letter dated April 18, 2012, the staff issued RAI B.1.34-2 requesting that the applicant describe how operating experience was considered. Specifically, the staff requested the applicant to describe the process used to find potential instances of cracking in ASME Code Class 1 small-bore piping and to provide details on any such instances. In addition, if cracking of ASME Code Class 1 small-bore piping was identified, the staff requested the applicant to either provide a plant-specific program that includes periodic inspections or to explain and justify why the One-Time Inspection Small-Bore Piping Program will adequately manage cracking.

By letter dated May 18, 2012, the applicant responded to RAI B.1.34-2. The applicant stated that it reviewed the paperless condition reporting system, which is used to track items in the site CAP. The applicant reviewed 10 years of operating experience documented in the paperless condition reporting system, and keyword searches, including the words “crack,” “leak,” “fracture,” and “spray,” were used in this review. Separately from the paperless condition reporting system, the applicant stated that it reviewed licensee event reports (LERs). The applicant also stated that another source of information was interviews with plant personnel on operating experience related to plant systems. The applicant explained that, over time, individuals involved in the day-to-day maintenance and operation of the plant acquire unique knowledge and experience regarding the performance history and degradation phenomenon affecting SSCs. For SSCs within the scope of license renewal, the applicant stated that system engineers were interviewed to reveal any potential AERM that would not otherwise be identified by the AMR process and operating experience document review. These interviews consisted of open discussions of system aging effects; aging mechanisms, aging effects, and adverse environments identified in industry guidance documents were also reviewed with the system engineers. The applicant further stated that the interviewers prompted the system engineers to discuss unusual or unique materials, environments, and aging effects and asked about system problems that may be age-related, which would include cracking of ASME Code Class 1 small-bore piping. Based on these activities, the applicant stated that GGNS has not experienced age-related cracking in ASME Code Class 1 small-bore piping.

The staff reviewed the applicant’s response and determined that, although GGNS has been operating for approximately 27 years, the applicant’s search of plant-specific operating experience in the paperless condition reporting system was limited to just 10 years. Also, the applicant stated that it supplemented the search of the paperless condition reporting system with a review of information from LERs. However, the staff determined that this information may not be sufficient or complete because LERs only include events that meet the reporting criteria of 10 CFR 50.72 and 10 CFR 50.73, and these criteria may not include all instances of cracking in ASME Code Class 1 small-bore piping. The applicant also stated that it relied on interviews of plant personnel. The staff determined that, while these interviews may provide additional context for previously documented information, they do not constitute an established repository of plant-specific operating experience information. By letter dated August 7, 2012, the staff issued RAI B.1.34-2a requesting the applicant provide a technical basis for limiting the review of plant-specific operating experience in the paperless condition reporting system, or other plant databases, to the previous 10 years of plant operation.

The applicant responded to RAI B.1.34-2a by letter dated September 4, 2012. The applicant stated that operating experience relevant to the program would be associated with leakage of ASME Code Class 1 reactor coolant pressure boundary piping components because such a condition requires submission of an LER. Thus, the applicant stated that its LER search provides a complete source for identification of through-wall cracking of ASME Code Class 1 small-bore piping. The applicant also stated that a review of records outside the paperless condition reporting system would provide no additional information. As to the technical basis for the plant-specific operating experience search, the applicant referenced the guidance in NEI 95-10, which states that a plant-specific operating experience review should include the prior 5 to 10 years of plant operating and maintenance history. The applicant stated that degradation due to aging mechanisms is a progressive phenomenon, so the rate of failures due to aging would be expected to increase with time, and a failure that may have occurred greater than 10 years ago and not recurred since would unlikely be attributed to age-related degradation.

The staff reviewed the applicant's justification for the completeness of the plant-specific operating experience review. Although NEI 95-10 recommends a review only of the prior 5 to 10 years of plant operating history, the staff determined that, in this case, following this general recommendation does not completely demonstrate that GGNS has not experienced cracking in ASME Code Class 1 small-bore piping. Industry operating experience shows that age-related cracking of small-bore piping can manifest even within the first 10 years of plant operation. In one example, described in LER 88-011-00, Byron Station, Unit 1 experienced age-related cracking within 4 years. The staff also determined that it is not evident as to why the LER reporting criteria of 10 CFR 50.73, given potential changes over the operating history of the plant, would capture all instances of non-through-wall cracking or would specifically apply to all instances of ASME Code Class 1 small-bore piping leakage. In addition, the staff determined that the applicant's response to RAI B.1.34-2 does not fully describe the results of the keyword search or justify why a search based on the keywords would capture all potential instances of age-related cracking in ASME Code Class 1 small-bore piping.

Based on its review of the responses to RAIs B.1.34-2 and B.1.34-2a, the staff determined that the applicant has not shown GALL Report AMP XI.M35 to be applicable to GGNS. By letter dated November 5, 2012, the staff issued RAI B.1.34-2b requesting that the applicant demonstrate applicability of the program by fully describing the process for and providing the results of the plant-specific operating experience review that covers the complete operating history of the plant. With respect to the review of the prior 10 years of condition reports, the staff requested the applicant to identify the specific keywords and justify why a search based on these keywords would identify all potential instances of age-related cracking in ASME Code Class 1 small-bore piping. With respect to the LER review, the staff requested the applicant to justify why the LER reporting requirements, considering changes over the course of the operating history of the plant, would capture all instances of non-through-wall cracking and specifically apply to all leakage of ASME Code Class 1 small-bore piping. The staff also requested the applicant to describe and justify the process or methodology used to review the LERs. For the period of time not covered by the condition report search, the staff requested the applicant to identify and justify the specific sources of information reviewed and the process or methodology used to find potential instances of cracking. Any relevant items found through these reviews were requested to be described.

The applicant responded to RAI B.1.34-2b by letter dated November 29, 2012. The applicant described the extent of its condition report review, stating that the review covered over 10,000 condition reports found through a search of 26 different keywords. Through this review the applicant found no items relevant to cracking of ASME Code Class 1 small-bore piping. On the review of LERs, the applicant indicated that ASME Code Class 1 components are those components in the reactor coolant system pressure boundary whose failure could cause loss of reactor coolant at a rate exceeding the capability of the normal makeup system. Reactor coolant pressure boundary leakage is not allowed by GGNS Technical Specification 3.4.5; therefore, the applicant stated that any leakage of ASME Code Class 1 small-bore piping is required to be reported in an LER. The applicant did not provide additional information on the review of plant operating experience during the period of time not covered by the prior 10-year condition report review. Instead, the applicant stated that such a review will be completed prior to the period of extended operation.

The staff reviewed the applicant's response to RAI B.1.34-2b and determined that the applicant's review of the prior 10 years of condition reports partially demonstrates applicability of GALL Report AMP XI.M35 to GGNS. This determination is based on the staff's finding that condition reports are an appropriate source for identifying potential instances of age-related cracking of ASME Code Class 1 small-bore piping. According to LRA Section 2.3.1.2 and the applicant's response, components of the reactor coolant pressure boundary whose failure could cause a loss of reactor coolant at a rate in excess of the normal makeup system capability are ASME Code Class 1. As reactor coolant pressure boundary components, ASME Code Class 1 small-bore piping components perform safety-related functions consistent with the definition in 10 CFR 50.2, which states that safety-related SSCs are those SSCs that are relied upon to remain functional during and following design basis events to assure the integrity of the reactor coolant pressure boundary. The quality assurance requirements of 10 CFR Part 50, Appendix B, apply to activities affecting the safety-related functions of SSCs; ASME Code Class 1 small-bore piping would be subject to these quality assurance requirements. Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B, requires measures to assure that conditions adverse to quality, such as failures, deficiencies, deviations, and nonconformances, are promptly identified and corrected, and Criterion XVII, "Quality Assurance Records," requires identifiable and retrievable records to furnish evidence of activities affecting quality. Cracking of ASME Code Class 1 small-bore piping would be considered as a deficiency, for example, and thus require corrective action and documentation as part of the quality assurance program. At the applicant's site, condition reports serve this purpose. The staff's determination is also based on the results of the applicant's search and review of condition reports. The keywords used in the applicant's search are directly applicable to age-related cracking of ASME Code Class 1 small-bore piping. For example, the direct effects of through-wall cracking would be evidenced by a leak, rupture, or spray, all of which were keywords used in the applicant's search. Non-through-wall cracking could be documented as a crack, or as a degraded, deteriorated, or damaged condition. Derivatives of these words were also used in the applicant's search. Several of the applicant's keywords, such as "corrosion," "rupture," "leak," "degrade," "damage," and "crack," were also identical to or derivatives of keywords used by the staff in its independent review of operating experience during the audit of this program. This review is described in the AMP Audit Report. Through this independent review the staff found several potential condition reports, but none were determined to directly involve age-related cracking of ASME Code Class 1 small-bore piping. Based on the appropriateness of the records reviewed by the applicant, the methodology used to search those records, and the results, the staff determined that the applicant has demonstrated that GGNS has not experienced age-related cracking of ASME Code Class 1 small-bore piping during the 10 years before submittal of the LRA. Therefore, the staff's concern in RAI B.1.34-2b on the methodology for reviewing the prior 10 years of condition reports is resolved.

Notwithstanding the above determination, the staff also determined that the applicant's response to RAI B.1.34-2b is incomplete because it does not fully cover the period of plant operation leading up to the 10-year period covered in the previously described condition report review. The applicant stated that it reviewed LERs from this period and found no instances of cracking in ASME Code Class 1 small-bore piping. However, the staff determined that the LER reporting requirements only capture instances where a crack resulted in reactor coolant pressure boundary leakage. Cracks in small-bore piping can also be detected before leakage occurs, for example, through examinations performed as part of applicant's existing Inservice Inspection Program. This type of cracking would not be captured in an LER, but would be documented in quality assurance program records. Although the applicant indicated that it will complete a review of these records prior to the period of extended operation, the staff determined that the methodology and results of this review are needed to support the review of the LRA. This information is necessary to demonstrate that the one-time inspections recommended by GALL Report AMP XI.M35 will ensure that the effects of aging will be adequately managed for ASME Code Class 1 small-bore piping. The staff identified this issue as Open Item 3.0.3.1.33-1.

By letter dated March 12, 2013, the staff issued RAI B.1.34-2c requesting that the applicant provide the results of a complete search and review of records in the condition reporting system. The staff requested that the applicant describe the methodology it used in this search to find potential instances of cracking in ASME Code Class 1 small-bore piping and to discuss any relevant items found. The applicant responded by letter dated April 15, 2013. The applicant stated that it completed an additional search of the condition reporting system for the period beginning from the start of licensed operation of the plant. The applicant searched the condition report records by using the key words "corrosion," "corrode," "rupture," "leak," "degrade," "damage," "fracture," and "crack." The applicant stated that it then reviewed each report generated from the keyword search results to identify any instances of cracking in ASME Code Class 1 small-bore piping. Based on this additional search, the applicant stated that it identified no instances of cracking.

The staff reviewed the response to RAI B.1.34-2c and determined that the applicant's search and review methodology is consistent with the approach applied in the applicant's review of the prior 10 years of condition reports, as described in the response to RAI B.1.34-2b. As previously discussed, the staff determined that this methodology is appropriate because these keywords are directly applicable to instances of age-related cracking of ASME Code Class 1 small-bore piping. The staff reviewed the applicant's LERs and a sample of inservice inspection summary reports for the period covered by the applicant's additional operating experience search and review to confirm the results. The staff found that this information supports the applicant's finding that there were no instances of age-related cracking of ASME Code Class 1 small-bore piping during this period. Therefore, the staff determined that the applicant has satisfactorily completed the search and review of condition reports for the period of plant operation leading up to the 10-year period already reviewed. The staff's concern described in RAI B.1.34-2c is resolved.

Because the applicant has completed a satisfactory review of plant-specific operating experience covering the complete operating history of the plant, and this review identified no instances of age-related cracking applicable ASME Code Class 1 small-bore piping, the staff determined that the applicant has demonstrated applicability of GALL Report AMP XI.M35 to GGNS. Open Item 3.0.3.1.33-1 is closed.

The “detection of aging effects” program element in GALL Report AMP XI.M35 recommends inspections based on susceptibility, inspectability, dose considerations, operating experience, and the limiting locations of the total population of ASME Code Class 1 small-bore piping. The GALL Report also states that opportunistic destructive examinations of socket welds may be performed and a sampling basis should be used if more than one weld is removed from service. However, during its audit, the staff found that the applicant’s One-Time Inspection – Small-Bore Piping Program does not include a methodology for selecting sample locations. The staff also found that the applicant’s program credits opportunistic destructive examinations, but does not discuss a sampling basis for these examinations when more than one socket weld is removed from service. By letter dated April 18, 2012, the staff issued RAI B.1.34-3, requesting that the applicant describe the methodology for selecting the inspection sample locations and discuss how this methodology accounts for susceptibility to cracking, inspectability, dose considerations, operating experience, and the limiting locations of the total population of ASME Code Class 1 small-bore piping. The staff also requested the applicant to describe the sampling basis that will be used to determine which welds will be destructively examined when more than one weld is removed from service.

In its response dated May 18, 2012, the applicant stated that the methodology for selecting the inspection sample locations will be consistent with GALL Report AMP XI.M35 and will be based on these factors:

- susceptibility to cracking, as determined by using industry guidance and operating experience, such as EPRI Report 1013389, “BWRVIP-155: BWR Vessel and Internals Project, Evaluation of Thermal Fatigue Susceptibility in BWR Stagnant Branch Lines” (BWRVIP-155)
- inspectability of the weld, as determined based on the weld configuration and location in the piping system
- dose considerations, as determined based on area dose rates at the physical location of each weld
- limiting locations of the total population of ASME Code Class 1 small-bore piping locations

The staff reviewed the applicant’s response and finds it acceptable because it indicates that the inspection locations under the One-Time Inspection – Small-Bore Piping Program will be based on the factors outlined in GALL Report AMP XI.M35. Specifically, in selecting the inspection locations, the applicant will consider which locations are more susceptible to cracking and which are limiting or practical for inspection based on inspectability and dose. The staff also finds acceptable the applicant’s use of the guidance in BWRVIP-155 because this report addresses industry operating experience concerning susceptibility to thermal fatigue for typical BWR plant piping configurations. Thermal fatigue is an aging mechanism that can lead to cracking, the primary aging effect managed by GALL Report AMP XI.M35. Selection of inspection locations based on operating experience is also recommended by GALL Report AMP XI.M35. LRA Section B.0.4 describes the applicant’s process for review of future plant-specific and industry operating experience to ensure that the AMPs, including One-Time Inspection – Small-Bore Piping Program, be effective in managing the effects of aging for which they are credited. The staff’s review of this process is discussed in SER Section 3.0.5.

In its response dated May 18, 2012, the applicant also addressed the staff’s request in RAI B.1.34-3 to describe the sampling basis for the destructive examinations. The applicant stated that, if removed from service, multiple welds may be destructively examined based on the sample selection criteria of GALL Report AMP XI.M35. The sample selection will be based on susceptibility, inspectability, dose considerations, operating experience, and the limiting locations of the total population of ASME Code Class 1 small-bore piping locations. The applicant further stated that the opportunistic destructive examinations will be performed when a weld is removed from service or for other considerations, such as plant modifications, and in the event that more than one weld is removed, the weld or welds considered most susceptible to cracking will be destructively examined. In addition, the applicant stated that the sampling requirements will be 10 percent of the total population, up to a maximum of 25 of both butt and socket welds. The staff finds the applicant's response acceptable because the welds considered most susceptible to cracking will be selected for destructive examination, and susceptibility to cracking will be determined based on the factors for selecting the inspection locations, both of which are consistent with the criteria in GALL Report AMP XI.M35. The staff's concern described in RAI B.1.34-3 is resolved.

Based on its audit and review of the LRA and the applicant's responses to RAIs B.1.34-1, B.1.34-2, B.1.34-2a, B.1.34-2b, B.1.34-2c, and B.1.34-3, 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.M35.

Operating Experience. LRA Section B.1.34 summarizes operating experience related to the One-Time Inspection – Small-Bore Piping Program. The LRA states that the program is new and industry operating experience will be considered when it is implemented. The LRA also states that plant-specific operating experience will be gained as the program is implemented, and this operating experience will be factored into the program through the "confirmation process" and "corrective actions" program elements. In addition, the LRA states that the program applies to the potential aging effect of cracking in ASME Code Class 1 piping less than 4 inches NPS, for which there is no operating experience at GGNS. The LRA further states that the program will use volumetric or destructive inspection techniques with demonstrated capability and a proven industry record to detect cracking in piping weld and base material.

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 AMP 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 "operating experience" program element in GALL Report AMP XI.M35 recommends volumetric inspection techniques that have a demonstrated capability and proven industry record to detect cracking in piping weld and base metal material. During its audit, the staff found that the applicant's One-Time Inspection – Small-Bore Piping Program includes volumetric examinations of full penetration welds using "demonstrated techniques"; however, there was insufficient information available on what constitutes a "demonstrated technique" or whether such techniques are capable of detecting cracking. By letter dated April 18, 2012, the staff issued RAI B.1.34-4 requesting that the applicant describe how the volumetric techniques used to examine full penetration welds are capable of detecting cracking.

In its response dated May 18, 2012, the applicant stated that a qualified ASME Code Section XI volumetric examination method, such as UT or radiography, is considered a "demonstrated technique." The applicant indicated that both of these methods have demonstrated the ability to detect cracking in the area of interest in full penetration small-bore welds when performed by

ASME-qualified personnel. In addition, the applicant stated that when performing ASME Code Section XI examinations at GGNS, ultrasonic examination techniques, equipment, and personnel performing the examinations comply with the standards of ASME Code Section XI as described in site procedures.

The staff finds the applicant's response acceptable because both ultrasonic and radiographic tests are volumetric and, when performed by qualified personnel, these examinations are capable of detecting discontinuities, such as cracks, that initiate from the inside diameter of piping. The inside diameter of ASME Code Class 1 small-bore piping is susceptible to cracking when exposed to reactor coolant, and this aging effect and environment is covered by GALL Report AMP XI.M35. The staff's concern described in RAI B.1.34-4 is resolved.

The LRA also states that the One-Time Inspection – Small-Bore Piping Program is new, and there is no operating experience at GGNS concerning cracking in ASME Code Class 1 small-bore piping. As discussed in SRP-LR Section A.1.2.3.10, for new programs, there may be other relevant plant-specific operating experience or generic industry operating experience that is relevant to the program elements, even though this operating experience was not identified through implementation of the new AMP. The SRP-LR further states that, for new programs, an applicant may need to consider the impact of relevant operating experience from implementation of its existing AMPs. The "detection of aging effects" program element in GALL Report AMP XI.M35 also addresses operating experience. It states that the generic program does not apply to plants that have experienced cracking in ASME Code Class 1 small-bore piping due to aging mechanisms. The staff's evaluation of the applicant's consideration of plant-specific operating experience for this program is addressed under the evaluation of the "detection of aging effects" program element, which is discussed above under the "Staff Evaluation" heading above.

UFSAR Supplement. LRA Section A.1.34 provides the UFSAR supplement for the One-Time Inspection – 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 found that the applicant's UFSAR supplement did not provide sufficient information for the administrative and regulatory control of the program because it did not describe certain characteristics of the program important for managing the effects of aging. The staff determined that the inspection sample size is important because it is used to establish whether cracking is occurring in ASME Code Class 1 small-bore piping; however, the applicant's UFSAR supplement did not specifically state the sample size. Also, during its audit, the staff found that the One-Time Inspection – Small-Bore Piping Program includes opportunistic destructive tests as a method for detecting aging effects. The examination techniques used under the program are important because they are used to detect the effects of aging; however, the applicant's UFSAR supplement did not state that the program detects aging through destructive examinations. By letter dated April 18, 2012, the staff issued RAI B.1.34-5 requesting that the applicant revise the summary description in LRA Section A.1.34 to specify the inspection sample size and that the program relies on destructive examinations, in addition to volumetric examinations, to detect aging effects. Alternatively, the staff requested the applicant to justify the adequacy of the program's administrative and regulatory controls.

In its response dated May 18, 2012, the applicant revised LRA Section A.1.34. The revision incorporates the provision to volumetrically examine 10 percent, with a maximum of 25, of the socket welds and 10 percent, with a maximum of 25, of the butt welds within the total population of ASME Code Class 1 small-bore piping welds. In addition, the revision incorporates the option to perform either volumetric or opportunistic destructive examination of socket welds. The revision also specifies that, for inspections of full penetration welds, volumetric examinations will be performed and, for socket welds, credit for two volumetric examinations will be taken in the event that a destructive examination is performed. The staff reviewed the revised UFSAR supplement and determined that it accurately reflects the inspection sample size and methods for detecting aging effects. These changes make the UFSAR supplement for the One-Time Inspection – Small-Bore Piping Program consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.1.34-5 is resolved.

Subsequently, by letter dated November 29, 2012, the applicant revised the UFSAR supplement to state that, prior to the period of extended operation, it will search the GGNS condition reporting system for all potential instances of cracking in ASME Code Class 1 small-bore piping for the period beginning at the start of licensed plant operation. This revision was consistent with the applicant's response to RAI B.1.34-2b, which the staff determined was incomplete, as discussed above under the "Staff Evaluation" heading. However, by letter dated April 15, 2013, the applicant provided the results for the completed condition report search and review. In this letter, the applicant also removed the statement from the UFSAR indicating that it would complete the search and review prior to the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by letter dated April 15, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection – 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).

3.0.3.1.34 Protective Coating Monitoring and Maintenance

Summary of Technical Information in the Application. LRA Section B.1.36 describes the existing Protective Coating Monitoring and Maintenance Program as consistent, with enhancements, with GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The LRA states that the AMP addressed service level 1 coatings inside containment and assesses coating condition through visual inspection.

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.S8.

The staff also reviewed the portions of the "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.1.36 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that "[t]he Protective Coating Monitoring and Maintenance Program will be enhanced to include parameters monitored or inspected per guidance in ASTM D5163-08." The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8. The staff finds it acceptable since the staff has confirmed that ASTM D5163-08 is acceptable for the parameters to be monitored and inspected since it is endorsed by the NRC in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," Revision 2.

Enhancement 2. LRA Section B.1.36 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that "[t]he Protective Coating Monitoring and Maintenance Program will be enhanced to provide for inspection of coating near sumps or screens associated with the ECCS. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8, and it is consistent with GALL Report AMP XI.S8 wording of "inspection shall also be carried out on all coatings near sumps or screens." Therefore, the staff finds that adding the coatings near sumps or screens is acceptable.

Enhancement 3. LRA Section B.1.36 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that "[t]he Protective Coating Monitoring and Maintenance Program will be enhanced to include acceptance criteria per ASTM D5163-08." The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8. The staff finds it acceptable since the staff has confirmed that ASTM D5163-08 is acceptable for the acceptance criteria since the NRC endorsed it in RG 1.54, Revision 2.

Operating Experience. LRA Section B.1.36 summarizes operating experience related to the Protective Coating Monitoring and Maintenance Program. The LRA states that visual inspections were completed in 2000, 2002, 2005, 2007, 2008, and 2010 with no conditions found that required immediate repair. In addition, some conditions were noted for future inspections.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.36 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 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 applicant's 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 enhancements and confirmed that they will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function 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).

3.0.3.1.35 Reactor Head Closure Studs

Summary of Technical Information in the Application. LRA Section B.1.37 describes the existing Reactor Head Closure Studs Program as consistent, with an exception, 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 program that manages cracking and loss of material for reactor head closure stud bolting using ISI and preventive measures. The LRA also states that the examination and inspection requirements specified in the ASME Code Section XI, Subsection IWB, Table IWB-2500-1, are used. The LRA further states that the program relies on recommendations listed in NUREG-1339 and NRC RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," to address reactor head closure stud bolting degradation.

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.M3. For the applicant's "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The program description of LRA Section B.1.37 states that ASME Section XI examination and inspection requirements specified in Table IWB 2500-1 are used. The LRA AMP also states that surface examination of reactor pressure vessel studs, nuts, and washers from 2001 through 2010 identified no relevant indications. However, the applicant's Appendix A of its Inservice Inspection Program dated June 26, 2000, indicates that VT-1 visual examinations, rather than surface examinations, were planned to be performed on closure nuts and washers, consistent with ASME Code Section XI, Table IWB-2500-1.

By letter dated April 18, 2012, the staff issued RAI B.1.37-2, requesting that the applicant:

(a) Clarify which methods of examinations are used to inspect the studs, nuts, washers, and flange threads. If the examination method is not consistent with those specified in ASME Code Section XI, as referenced in the GALL Report, justify why the examination method is acceptable to detect and manage the aging effects.

(b) Summarize the inspection results for the following ASME Code inspection items, for the period (2001-2010) discussed in the LRA, to confirm the effectiveness of the program: (1) volumetric examinations of the closure studs and RV flange threads, and (2) visual examination of the nuts and washers.

In its response dated May 18, 2012, the applicant stated that inspections are performed to ASME Section 2001 Edition through 2003 Addenda, Table IWB 2500-1, Examination Category B-G-1. The applicant also stated that the nuts and washers were examined by visual, VT-1, and studs and flange threads were examined by volumetric examination using UT. In addition, the applicant stated that volumetric examinations were performed on all 76 RV studs and flange threads during the period from 2001 to 2010, and no indications were noted. The applicant also stated that during the same inspection period, visual examinations were performed on all nuts and washers, and again no indications were identified.

The staff finds the applicant's response acceptable because the applicant's reactor head closure stud bolting components are examined in accordance with Examination Category B-G-1 of ASME Code, Section XI, Table IWB-2500-1, as recommended in GALL Report AMP XI.M3. Furthermore, the examinations performed on all of the applicant's closure studs, flange threads, nuts, and washers during the period from 2001 to 2010, did not identify any indication. Therefore, the staff's concern described in RAI B.1.37-2 is resolved.

The staff also reviewed the portions of the "preventive actions" program element associated with the exception to determine whether the program will be adequate to manage the aging effects for which it is credited. During the course of this review, the staff found the need to also review portions of the "corrective actions" program element, as discussed below. The staff's evaluation of this exception follows.

Exception. LRA Section B.1.37 states an exception to the "preventive actions" program element of GALL Report AMP XI.M3. NUREG-1801 recommends use of bolting material for closure studs that have an actual measured yield strength less than 150 ksi. The applicant stated that it does not have actual measured yield strength data. During its audit, the staff noted that the "corrective actions" program element of GALL Report AMP XI.M3 also has a similar recommendation for replacement bolting. However, onsite program documentation did not clearly indicate whether the applicant's "corrective actions" program element is consistent with the GALL Report in using replacement bolting materials that have a measured yield strength of less than 150 ksi.

By letter dated April 18, 2012, the staff issued RAI B.1.37-1 requesting the applicant to clarify if the "corrective actions" program element is consistent with the GALL Report in terms of using replacement bolting materials with a measured yield strength less than 150 ksi. In addition, the staff requested that if the "corrective actions" program element is not consistent with the GALL Report, the applicant identify this as a program exception, and provide justification for why the Reactor Head Closure Studs Program, with the cited exception, is adequate in managing the aging effects of replacement bolting. Finally, the staff also asked that the applicant revise the LRA as necessary, consistent with its response to RAI B.1.37-1.

In its response dated May 18, 2012, the applicant stated that the cited exception to the "preventive actions" program element also applies to the "corrective actions" program element. As part of its response to RAI B.2.37-1, the applicant revised LRA Section B1.37, to cite the additional exception of its "corrective actions" program element to the corresponding program element of GALL Report AMP XI.M3. In addition, the applicant stated that its justification, which is stated in the LRA for the "preventive actions" program element, also applies to the "corrective actions" program element for replacement bolting.

In its review, the staff finds that the applicant's response to RAI B.1.37-1 includes an appropriate revision to the LRA to identify the exception to the "corrective actions" program element of the Reactor Head Closure Studs Program in addition to the exception to the "preventive actions" program element.

In its review, the staff also noted that the recommendation to use closure bolting with measured yield strength of less than 150 ksi is related to a threshold susceptibility of higher strength materials to SCC. A review of the applicant's UFSAR Section 5.3.1.7 indicated that the applicant's reactor head closure studs, nuts, and washers are fabricated from SA-540 Grade B23 or B24 material with a specified minimum yield strength of 130 ksi, and a maximum reported ultimate tensile strength less than 170 ksi. Since the applicant stated that it does not have data regarding actual measured yield strength for its current or replacement closure bolting, it has appropriately and conservatively assumed that the closure bolting material is susceptible to SCC.

To manage cracking due to SCC, the applicant's program includes ultrasonic examination of each closure stud during each inspection period. The staff finds that the ultrasonic examination provides reasonable assurance that SCC in closure studs, should it occur, will be detected and managed before loss of intended function. In addition, the previous volumetric examinations of the closure studs have not indicated any evidence of SCC. Therefore, the staff finds the applicant's exceptions to the "preventive actions" and "corrective actions" program elements concerning use of material with yield strength equal or greater than 150 ksi acceptable. The staff's concerns described in RAI B.1.37-1 are resolved.

Summary. Based on its audit, and review of the applicant's Reactor Head Closure Studs Program, the staff finds that the program elements one, three, four, five, and six, 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 exceptions associated with the "preventive actions" and "corrective actions" program elements and the applicant's response to RAIs B.1.37-1 and B.1.37-2. Based on its review, the staff finds the applicant's proposed AMP, with exceptions, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.3.7 summarizes operating experience related to the Reactor Head Closure Studs Program. The applicant stated that examinations performed on the closure studs, nuts, and washers from 2001 to 2010 identified no relevant indications. The applicant also indicated that these examinations in accordance with the ASME Code requirements are widely used and have been demonstrated effective at detecting aging effects during the ISIs. The applicant further stated that the application of these proven methods provides assurance that the effects of aging will be managed such that the reactor head closure studs will continue to perform their intended functions consistent with the CLB through the period of extended operation.

The staff reviewed operating experience information in the LRA 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 AMP 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 audit and 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.

During the audit and review of the applicant's database, the staff noted that in 1986 the applicant discovered that two of the closure studs were undersized. The condition report did not provide any additional information regarding the applicant's finding. During the audit, the staff requested additional information from the applicant on the referenced undersized studs, such as which portions of the studs were undersized, and, if corrected, how the condition was corrected. However, the information was not available to the staff during the audit.

By letter dated April 18, 2012, the staff issued RAI B.1.37-3 requesting that the applicant clarify if the "undersized" studs are in service and will continue to be in service during the period of extended operation. In addition, if the studs are in service the staff requested the applicant to provide the following additional information: (a) location of the studs in the RV head flange, (b) inspection results for the studs, (c) information to justify the adequacy of the undersized studs for continued use, including engineering evaluations such as stress and fatigue analyses, and (d) justification of the adequacy of the program to manage the aging effects of the undersized studs. If the undersized studs were replaced, the staff requested that the applicant provide information on the material properties and surface coatings for the replaced studs.

In its response dated May 18, 2012, the applicant stated that the "undersize" condition noted in the 1986 documentation was a slight oversize condition of the bottom plug hole for two reactor head closure studs. The applicant also stated that the condition had been identified before initial startup. The applicant further stated that the condition was determined acceptable and, therefore, the studs are still in service. Finally, the applicant stated that there was no condition involving the outside diameter of the studs.

Based on its review, the staff finds the applicant's response to RAI B.1.37-3 acceptable because the applicant clarified that the "undersized" condition reported in 1986, involved a slight oversize condition of stud bottom plug holes for two reactor head closure studs. The staff finds that the slight oversize condition of stud bottom plug holes is not critical to maintain the intended function of the closure studs. Furthermore, the applicant had identified the condition before startup and determined it was acceptable. In addition, the outside diameter of the studs is not affected and the 2001 through 2010 volumetric examinations of the subject studs did not note any indication of stud degradation. Therefore, the staff's concern described in RAI B.1.37-3 is resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs B.1.37-1, B.1.37-2, and B.1.37-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.37 provides the UFSAR supplement for the Reactor Head Closure Studs 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 audit and review of the applicant's Reactor Head Closure Studs 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).

3.0.3.1.36 Reactor Vessel Surveillance

Summary of Technical Information in the Application. LRA Section B.1.38 describes the existing Reactor Vessel Surveillance Program as consistent, with exception and enhancement, with GALL Report AMP XI.M31, "Reactor Vessel Surveillance." The Reactor Vessel Surveillance Program manages reduction of fracture toughness for reactor vessel beltline materials using material data and dosimetry. The program includes all reactor vessel beltline materials as defined by 10 CFR Part 50, Appendix G, Section II.F, and complies with 10 CFR Part 50, Appendix H, for vessel material surveillance. The applicant participates in an ISP, which is based on the BWRVIP documents, as approved by the NRC staff.

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.M31. 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 in GALL Report AMP XI.M31 recommends monitoring all of the beltline materials as defined by 10 CFR Part 50, Appendix F. The GALL Report also states that materials originally monitored within the scope of the licensee's existing 10 CFR Part 50, Appendix H, materials surveillance program will continue to serve as the basis for the reactor vessel surveillance aging management program unless safety considerations for the term of the renewed license would require the monitoring of additional or alternative materials.

LRA Table 4.2-2 for the applicant's upper-shelf energy analysis includes analysis results for "Shell Plate 1" material. The LRA also indicates that the 1/4T fluence of this plate is $3.94x10^{17}$ n/cm^2 (E > 1 MeV) for 54 effective full-power years (EFPYs) in consideration of the planned EPU. The projected operation period of 54 EFPY corresponds to the end of the period of extended operation. The projected fluence of Shell Plate 1 exceeds $1.0x10^{17}$ n/cm^2, which is a fluence threshold for the consideration in a Reactor Vessel Surveillance Program in accordance with 10 CFR Part 50, Appendix H. During the audit, the staff also noted that Shell Plate 1 has the highest adjusted reference temperature (ART) for 54 EFPY among all the plates of the applicant's reactor vessel.

In its review of the LRA, the staff further noted that the LRA information does not permit the staff to independently confirm the neutron irradiation embrittlement of all relevant beltline materials, including the shell plate material and other extended beltline materials, for the period of extended operation. In addition, the LRA does not clearly address how the applicant's program will monitor and use actual test data related to the new limiting material (i.e., Shell Plate 1), including the data of the ISP, in order to achieve the program objective specified in the GALL Report (i.e., to provide sufficient material data and dosimetry to monitor irradiation embrittlement and to determine the need for operating restrictions). The staff also noted that the general description of the program in LRA Section B.1.38 includes references to BWRVIP-102 and BWRVIP-135 that have never been submitted to the NRC for approval.

By letter dated June 27, 2012, the staff issued RAI B.1.38-1 requesting that the applicant provide a new table to reflect all the relevant material properties for the beltline and extended beltline materials. The staff also requested that the new table include the heat numbers, material compositions (copper and nickel contents), unirradiated reference temperature (RT_{NDT}) data, projected neutron fluences, and calculated ART values of the reactor vessel materials for the period of extended operation (54 EFPY). The staff further requested the applicant to clarify how the applicant's program will interact with the BWRVIP ISP and will use the data generated by the ISP for the period of extended operation. In addition, the staff requested the applicant remove references to the BWRVIP documents that have not been submitted for approval.

In its response dated July 26, 2012, the applicant revised LRA Section 4.2.1 to add a new table that provides the requested information for the beltline and extended beltline materials. The new table is LRA Table 4.2-5, GGNS Beltline Adjusted Reference Temperature (ART) Values (54 EFPY)," which lists the beltline materials, including the extended beltline materials, and their heat numbers, copper and nickel contents, chemistry factors, fluence levels, and data regarding RT_{NDT} and ART for the period of extended operation (54 EFPY).

The applicant also indicated that as a member of the BWRVIP ISP, monitoring and use of actual test data related to the new limiting material of Shell Plate 1 is conducted in accordance with BWRVIP-86, Revision 1, and BWRVIP-135, Revision 2. The applicant further indicated that as required by BWRVIP-135, Revision 2, Section 3, plants are required to notify the BWRVIP of changes in fluence projections for the reactor pressure vessel (at inner diameter and 1/4T locations) and the latest ART tables.

In addition, the applicant stated that it will ensure that new fluence projections throughout the period of extended operation and latest beltline ART values are provided to the BWRVIP prior to the period of extended operation. The applicant also revised LRA Sections A.1.38 (UFSAR supplement) and B.1.38 (program description) accordingly to identify this item as an enhancement to the "monitoring and trending" program element. The staff's evaluation of this enhancement is described below. The following evaluation is also addressed in the evaluation section for Enhancement 2.

The applicant further stated that LRA Sections A.1.38 and B.1.38 are revised to remove references to BWRVIP-102 and BWRVIP-135, and the correct statement for these sections is, "The NRC staff has approved an integrated surveillance program for the period of extended operation based on BWRVIP-86, Revision 1."

In its review, the staff found that the applicant's new table (LRA Table 4.2-5) is appropriate because the LRA table provides the information that the staff requested for its independent confirmation. The staff also confirmed that the applicant adequately determined the ARTs of the reactor vessel beltline and extended beltline materials, using the data described in the table. In addition, the staff found that the removal of the references to BWRVIP-102 and BWRVIP-135 from the LRA is adequate because these BWRVIP documents have not been submitted to the NRC for approval. The staff's concern described in RAI B.1.38-1 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.M31 recommends the integrated surveillance program shall have at least one capsule with a projected neutron fluence equal to or exceeding the 60-year peak reactor vessel wall neutron fluence prior to the end of the period of extended operation.

In comparison, LRA Section B.1.38 indicates the applicant's program relies on the BWRVIP ISP based on staff-approved BWRVIP documents to meet the 10 CFR Part 50, Appendix H, requirements. The LRA also refers to BWRVIP-86, Revision 1, "BWR Vessel and Internals Project Updated BWR Integrated Surveillance Program (ISP) Implementation Plan," as described in a program enhancement (Enhancement 1). The ISP is an approved method for the commercial BWR reactors to manage the neutron embrittlement of the reactor vessel materials.

Table 4-7 of BWRVIP-86, Revision 1, indicates that the maximum fluence values (E > 1 MeV) of the tested surveillance plate and weld materials for the applicant‘s reactor vessel are 2.66×10^{18} n/cm^2 and 2.75×10^{18} n/cm^2, respectively. BWRVIP-86, Revision 1, also indicates that only two additional weld materials will be withdrawn additionally in 2013 and 2039 for the applicant's program, which correspond to estimated fluence values of 1.35×10^{18} n/cm^2 and 2.67×10^{18} n/cm^2, respectively.

In addition, LRA Sections 4.2 and 4.2.1 indicate that 54 EFPY corresponds to the end of the period of extended operation and the peak 1/4T fluence for 54 EFPY with the planned EPU is 3.02×10^{18} n/cm^2 as projected for the lower-intermediate shell and axial welds. The peak ID fluence of the reactor vessel for 54 EFPY is 4.44×10^{18} n/cm^2. These fluence values (E > 1 MeV) are compared as follows, indicating that the LRA fluence projection for the reactor vessel in consideration of the planned EPU exceeds the fluence values of tested and to-be-tested surveillance materials in the BWRVIP ISP:

- Maximum fluence of the tested surveillance plate materials (ISP): 2.66×10^{18} n/cm^2
- Maximum fluence of the tested surveillance weld materials (ISP): 2.75×10^{18} n/cm^2
- Fluence of the surveillance weld to be withdrawn in 2039 (ISP): 2.67×10^{18} n/cm^2
- Peak ID fluence of the reactor vessel (LRA with EPU): 4.44×10^{18} n/cm^2
- Peak 1/4T fluence of the reactor vessel (LRA with EPU): 3.02×10^{18} n/cm^2

In its review, the staff further noted that the LRA does not clearly address whether the peak ID fluence of the reactor vessel for 54 EFPY with the planned EPU is projected to exceed the maximum fluence of the ISP surveillance materials (for either weld or plate).

By letter dated June 27, 2012, the staff issued RAI B.1.38-2 requesting that the applicant clarify whether the peak ID fluence of the reactor vessel for 54 EFPY in consideration of the planned EPU is projected to exceed the maximum fluence of the surveillance materials (for either weld or plate). The staff also requested that if the peak ID fluence of the reactor vessel for 54 EFPY is projected to exceed the maximum fluence of the ISP surveillance materials, the applicant modify the LRA to include an exception, or explain how its Reactor Vessel Surveillance Program is consistent with the GALL Report.

In its response dated July 26, 2012, the applicant stated that the peak reactor vessel ID fluence for weld and plate material is expected to exceed the [surveillance] fluence values for GGNS listed in BWRVIP-86, Revision 1, Table 4-7, before reaching 54 EFPY. The applicant also indicated that this is not consistent with the GALL Report and should be considered an exception to the “detection of aging effects” program element of GALL Report AMP XI.M31. In addition, the applicant provided a revision to LRA Section B.1.38 to identify this item as a program exception.

The applicant further stated that in a letter dated November 4, 2003, GGNS was issued License Amendment No. 160 approving participation in the BWRVIP ISP; and in an SER dated October 20, 2011, the staff approved BWRVIP-86, Revision 1, which is an updated BWRVIP ISP for the period of extended operation. The applicant also stated that BWRVIP-86, Revision 1, Section 5, includes provisions to apply the embrittlement evaluation described in RG 1.99, Revision 2, for evaluating materials and calculating an ART. The applicant indicated that the use of RG 1.99, Revision 2, to project the embrittlement evaluation is also described in the “monitoring and trending” program element of GALL Report AMP XI.M31.

In its review, the staff found that the applicant appropriately identified a program exception related to the program not being expected to have a capsule with a projected neutron fluence level equal to or exceeding the 60-year peak reactor vessel wall neutron fluence prior to the end of the extended period. The staff also confirmed the applicant revised LRA Section B.1.38, consistent with the program exception. In addition, the staff found the applicant's response acceptable because (a) the applicant participates in the staff-approved BWRVIP ISP, which generates and evaluates the embrittlement trend data of the BWR fleet reactor vessels, including the data for the surveillance materials of the applicant's reactor vessel, (b) the BWRVIP ISP and GALL Report include the provisions to use the guidance in RG 1.99, Revision 2, in determining the embrittlement levels of reactor vessel materials, and (c) the projected peak 1/4T fluence of the applicant's reactor vessel (3.02×10^{18} n/cm^2) with EPU is not significantly higher than the maximum surveillance fluence levels of the surveillance plate and weld materials that represent the applicant's vessel materials (2.66×10^{18} n/cm^2 and 2.75×10^{18} n/cm^2 for plate and weld, respectively). The staff's concern described in RAI B.1.38-2 is resolved.

The applicant's program enhancement and exception, which the applicant identified in its amended LRA, are also described in the evaluation sections for program enhancement and exception as follows. The staff reviewed the portions of the "monitoring and trending" program element 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 program exception also follows.

Exception. As discussed above, the applicant amended the LRA in response to RAI B.1.38-2, by letter dated July 26, 2012. The amended LRA identifies a program exception to the "detection of aging effects" program element. In this exception, the applicant stated that the applicant's program is not expected to have a capsule with a projected neutron fluence level equal to or exceeding the 60-year peak reactor vessel wall neutron fluence prior to the end of the extended period.

As described above in the staff's evaluation regarding RAI B.1.38-2, the staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M31 and finds it acceptable because (a) the applicant participates in the staff-approved BWRVIP ISP, which generates and evaluates the embrittlement trend data of the BWR fleet reactor vessels, including the data for the surveillance materials of the applicant's reactor vessel, (b) the BWRVIP ISP and GALL Report include the provisions to use the guidance in RG 1.99, Revision 2, in determining the embrittlement levels of reactor vessel materials, and (c) the projected peak 1/4T fluence of the applicant's reactor vessel with EPU is not significantly higher than the maximum fluence of the surveillance plate and weld materials that represent the applicant's vessel materials.

Enhancement. LRA Section B1.38 states an enhancement to the "monitoring and trending" program element. The applicant stated that the enhancement would ensure that any additional requirements specified in the final NRC SE for BWRVIP-86, Revision 1, will be addressed before the period of extended operation. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M31, and the staff determined the need for additional information, which resulted in the issuance of an RAI as discussed below.

The conclusion section of the staff's SE for BWRVIP-86, Revision 1, dated October 20, 2011, states that BWRVIP-86, Revision 1, is acceptable subject to the conditions discussed in previous SEs (e.g., staff's evaluation regarding BWRVIP-116), where such conditions have not been superseded by the SE regarding BWRVIP-86, Revision 1. Therefore, during its review of the program enhancement, the staff found that there are no "additional requirements" in the NRC SE of BWRVIP-86, Revision 1, other than those already identified for BWRVIP-116 and BWRVIP-86. By letter dated June 27, 2012, the staff issued RAI B.1.38-4 requesting that the applicant clarify what will be included in the "additional requirements."

In its response dated July 26, 2012, the applicant indicated that BWRVIP-86, Revision 1, has combined BWRVIP-86-A, BWRVIP-116, and associated implementation activities into a single implementation plan for the BWRVIP ISP, covering plant operation to 60 years. The applicant also indicated that BWRVIP-86, Revision 1, incorporated the staff's final SE for BWRVIP-116. The applicant further indicated that the applicant's enhancement will ensure that (a) the requirements of the ISP specified in BWRVIP-86, Revision 1, including the conditions of the staff's SE for BWRVIP-116, will be addressed before the period of extended operation, and (b) the new fluence projections throughout the extended operation and latest beltline ART values are provided to the BWRVIP prior to the period of extended operation. In addition, the applicant provided revisions to LRA Section A.1.38 (UFSAR supplement) and LRA Section B.1.38 (program description), consistent with the applicant's response.

In its review, the staff finds the applicant's response acceptable because the applicant's revisions to LRA Sections A.1.38 and B.1.38 clarify that the program enhancement ensures that the requirements of the BWRVIP ISP, specified in BWRVIP-86, Revision 1, will be adequately addressed before the period of extended operation. The staff's concern described in RAI B.1.38-4 is resolved.

Summary. Based on its audit, and review of the applicant's responses to RAIs B.1.38-1, B.1.38-2, and B.1.38-4, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M31. The staff also reviewed the exception associated with the "detection of aging effects" program element, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancement associated with the "monitoring and trending" program element and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.38 summarizes operating experience related to the applicant's Reactor Vessel Surveillance Program. The LRA indicates that the applicant committed to using the BWRVIP ISP, and as part of the ISP, the applicant is not required to withdraw any capsules from the applicant's reactor vessel. The LRA also indicates that material property data for the plant's limiting materials can be projected into the future with data from other plants. In addition, the applicant stated that updated values for its vessel fluence and applicable ISP data were used to evaluate the impact of neutron embrittlement on the P-T limits and the analysis in this evaluation confirmed that the reduction of fracture toughness due to neutron embrittlement is adequately managed.

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 AMP 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, with the exception of the following item. 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.

LRA Sections 4.2 and 4.2.1 and Table 4.2-1 indicate that the peak 1/4T fluence value of the reactor vessel for 54 EFPY is 3.02×10^{18} n/cm^2 (E > 1MeV) as projected for lower-intermediate shell and axial welds in consideration of the EPU. In comparison, the applicant's previous fluence projections without the consideration of EPU are described as follows.

The applicant's program credits the ISP specified in BWRVIP-86, Revision 1. Tables 7-2 and 7-3 and Section 7.2 in BWRVIP-86, Revision 1, indicate that the 1/4T fluence of the applicant's reactor vessel materials estimated for 48 EFPY is 1.8×10^{18} n/cm^2 (E > 1 MeV). This 1/4T fluence for 48 EFPY is equivalent to 2.03×10^{18} n/cm^2 for 54 EFPY based on linear extrapolation from 48 to 54 EFPY. This 54-EFPY neutron fluence (2.03×10^{18} n/cm^2) based on the fluence data in BWRVIP-86, Revision 1, is equivalent to the fluence in UFSAR Section 5.3.1.6.2, "Neutron Fluence." The UFSAR section indicates that the 1/4T fluence of the reactor vessel beltline region for 32 EFPY is 1.21×10^{18} n/cm^2, and this fluence value for 32 EFPY is converted to 2.04×10^{18} n/cm^2 for 54 EFPY using linear extrapolation.

In addition, UFSAR Sections 4.3.2.8, 5.3.1.6.1, and 5.3.1.6.2 indicate that the updated lead factor for this fluence projection for 32 EFPY is based on 3-degree surveillance capsule dosimetry data. However, the applicant's letter dated May 5, 1994, in response to GL 92-01 indicates that the 1/4T fluence at the end of original 40-year license (32 EFPY) is 2.11×10^{18} n/cm^2 as determined from flux wire dosimetry measurements at the applicant's reactor vessel (without consideration of planned EPU). This fluence value is converted to 3.56×10^{18} n/cm^2 for 54 EFPY using linear extrapolation.

With the aforementioned assumption that linear extrapolation of the fluence is applicable, these 1/4T fluence values (E > 1 MeV) projected for 54 EFPY are compared as follows:

- Projection based on the data in the 1994 letter: 3.56×10^{18} n/cm^2 (without EPU)
- Projection based on the data in BWRVIP-86, Revision 1: 2.03×10^{18} n/cm^2 (without EPU)
- Projection based on the data in the UFSAR: 2.04×10^{18} n/cm^2 (without EPU)
- LRA Section 4.2.1: 3.02×10^{18} n/cm^2 (with EPU)

In its review, the staff noted that the "operating experience" program element of the AMP does not provide sufficient information to demonstrate the adequacy of the applicant's dosimetry monitoring activities which are part of the Reactor Vessel Surveillance Program. For example, the LRA does not clearly address why the 1/4T fluence projected for 54 EFPY based on the fluence information in the applicant's 1994 letter is significantly greater than the other fluence values described above.

By letter dated June 27, 2012, the staff issued RAI B.1.38-3 requesting that the applicant provide the following information regarding the neutron dosimetry data obtained and to be obtained in the program: (a) the withdrawal schedule of the dosimetry capsules/wires (including the dosimetry data addressed in UFSAR Section 5.3.1.6.1 and applicant's letter dated May 5, 1994), and (b) the results of the benchmark of the flux calculations with the dosimetry data. The staff also requested that the applicant clarify why the 1/4T fluence for 54 EFPY projected from the fluence information in the 1994 response significantly exceeds the other fluence values addressed above. The staff further requested that as part of the response, the applicant justify why the 54-EFPY fluence in the LRA that considers EPU is less than the 54-EFPY fluence projected using the dosimetry-based 32-EFPY fluence in the 1994 letter with no consideration of EPU. In addition, the staff requested that the applicant justify why the dosimetry monitoring activities are adequate to provide sufficient dosimetry for the Reactor Vessel Surveillance Program, consistent with the GALL Report.

In its response dated July 26, 2012, the applicant stated that flux wire was pulled at the end of the first operating cycle, and the results from the flux wire had been used in the fluence evaluations performed through operating cycle 13. The applicant also indicated that since it has been approved to use the ISP to meet the Appendix H requirements (November 4, 2003), there is no plan for future withdrawals of dosimetry wires or capsules from the applicant's reactor vessel. The applicant further indicated that with input from the BWRVIP, the first cycle flux wire dosimetry results have been shown to be over-conservative and unreliable for reasonable end-of-license fluence projections.

In addition, the applicant indicated that BWRVIP-86, Revision 1, Section 5, includes provisions for ongoing vessel dosimetry for plants that do not have dosimetry capsules tested. The applicant stated that the dosimetry activities for the applicant's Reactor Vessel Surveillance Program are adequate and, therefore, consistent with the GALL Report.

In comparison with the applicant's response, the staff noted that BWRVIP-86, Revision 1, Section 5.4, "Plan for Ongoing Vessel Dosimetry," states that if a plant has not previously tested a capsule, but has tested a first-cycle dosimeter, the first-cycle dosimetry is generally the basis for its current fluence projection. The staff also noted that the applicant's response does not provide a technical basis for why the fluence, which is based on the first-cycle dosimetry data, is overly-conservative and unreliable for the 54-EFPY fluence projections. Therefore, the staff needed additional information to determine the adequacy of the operating experience program element. By letter dated October 17, 2012, the staff issued RAI B.1.38-3a, requesting the applicant to explain why the first-cycle flux wire dosimetry results are considered to be unreliable for reasonable end-of-license fluence projections.

In the November 15, 2012, response, the applicant stated:

> First cycle dosimetry data are unreliable because initial core configurations are atypical of other cycles. General Electric Hitachi (GEH) flux wire measurement data indicate that first cycle flux measurements are often overly conservative in comparison to flux measurements taken after later cycles. However, in some cases, first cycle measurements are not conservative. Therefore, first cycle dosimetry data are considered unreliable for reasonable end-of-license fluence projections.

The staff's concern described in RAIs B.1.38-3 and B.1.38-3a are related to the adequacy of the fluence measurements as part of the Reactor Vessel Surveillance Program. The staff agrees that the first cycle flux measurements are unreliable, and therefore, the Reactor Vessel Surveillance Program will rely on the calculated fluence values. However, the applicant's methodologies for fluence calculations, documented in SER Section 4.2.1, are still under review as part of Open Item 4.2.1 1 where the staff noted that the applicant's fluence calculation uncertainty analysis was not consistent with RG 1.190, and the errors associated with the two different fluence calculation methods are expected to propagate when the two methods are combined. The staff's concern described in RAIs B.1.38-3 and B.1.38-3a can be resolved with acceptable resolution of the Open Item. This issue therefore is part of Open Item 4.2.1-1. As documented in Section 4.2.1, Open Item 4.2.1-1 is closed. The staff confirmed that the applicant incorporated an NRC-approved single fluence method (MPM method) into its current licensing basis with appropriate fluence projections for 60 years of operation. The staff also noted that the qualification of the fluence method included an adequate evaluation of GGNS Cycle 1 dosimetry data. In its letter dated July 29, 2015 (response to RAI 4.2.1-2c(5)(b)), the applicant provided the updated reactor vessel fluence values based on the staff-approved MPM fluence methodology. The staff finds that the updated fluence values are acceptable to use in the applicant's program. In addition, the staff's evaluation regarding neutron embrittlement TLAAs are documented in Sections 4.2.2 – 4.2.6 of this SER. The staff's concern described in RAIs B.1.38-3 and B.1.28-3a is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAIs, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.38 provides the UFSAR supplement for the applicant's Reactor Vessel Surveillance 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 LRA Section A.1.38 does not address some of the important program attributes included in the UFSAR supplement described in SRP-LR, Table 3.0-1. By letter dated June 27, 2012, the staff issued RAI B.1.38-5 requesting that the applicant justify why some of important program attributes are not included in the supplement.

In its response dated July 26, 2012, the applicant stated that most of the important program attributes are incorporated by referencing BWRVIP-86, Revision 1. The one significant attribute of the program that is not explicitly controlled by the ISP would be the control of standby capsules in the applicant's reactor vessel. The applicant stated that to address this issue, LRA Section A.1.38 is revised to clearly state that the standby capsules at GGNS may be required for contingencies of the ISP, and as a result, any change to the status of the standby capsules, must be approved by the NRC prior to implementation, and untested capsules, which are placed in storage, must be maintained for future insertion. In its response, the applicant also provided a revision to the LRA Section A.1.38, consistent with the response.

The staff finds the applicant's response acceptable because the revised UFSAR supplement, which includes the reference to BWRVIP-86, Revision 1, and the provisions regarding the stand-by and untested capsules, is adequate to summarize the applicant's aging management program. Therefore, the UFSAR supplement for the applicant's Reactor Vessel Surveillance Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.1.38-5 is resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated July 26, 2012, is an adequate summary description of the program.

Applicant's July 29, 2015, response to RAI 4.2.1-2c(5)(b) provided slightly different fluence values due to the implementation of the single MPM fluence calculation methodology, but the conclusions regarding program acceptability remain the same.

Conclusion. On the basis of its audit and review of the applicant's Reactor Vessel Surveillance 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.M31. 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. Also, the staff reviewed Enhancement 1 and confirmed that its implementation through Commitment No. 27 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff reviewed the UFSAR supplement for this AMP and finds that the information in the UFSAR supplement, as amended by letter dated July 26, 2012, is an adequate summary description of the program.

3.0.3.1.37 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B.1.39 describes the existing "Regulatory Guide (RG) 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," as consistent, with enhancements, with GALL Report AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants." The LRA states that this is an existing program that requires periodic monitoring of water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner. The LRA also states that the program contains guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and content of inspection reports.

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.S7.

The staff also reviewed the portions of the "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.1.39 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be clarified to specify that detection of aging effects will monitor accessible surfaces on a frequency not to exceed 5 years. 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, the inspection frequency will be consistent with the recommendation identified in the GALL Report AMP.

Enhancement 2. LRA Section B.1.39 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates will be conducted at a frequency of at least every 5 years. The enhancement also states that the program owner will review the results and evaluate anomalies and perform trending of the results to provide reasonable assurance that degradation of inaccessible structures will be detected before loss of an intended function. 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, the inspection frequency and parameters monitored and analyzed will be consistent with the recommendations identified in the GALL Report AMP.

Enhancement 3. LRA Section B.1.39 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that quantitative acceptance criteria for evaluation and acceptance will be based on guidance provided in ACI 349.3R.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R provides a three-tier acceptance criteria (including quantitative criteria) for determining the adequacy of observed aging effects and specifies criteria for further evaluation. When this enhancement is implemented, it will make the acceptance criteria consistent with the recommendations identified in the GALL Report.

Summary. Based on its audit of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, the staff finds that program elements one through six 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 associated with the "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.1.39 summarizes operating experience related to the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. Program basis documentation indicated that during a walkdown in 1997 of the "A" and "B" SSW basins, discolored efflorescence was noted on the north face of both pump houses. Pictures were taken of the two affected areas, and a chemical composition analysis of the discolored efflorescence was performed. A subsequent walkdown of this area conducted in 2007, under the "Maintenance Rule," noted that no observable concrete damage such as concrete spalling was observed, and the condition was determined to be similar to that when first observed in 1997. The applicant determined that there was no immediate structural integrity concern for the next two plant operating cycles.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.39 provides the UFSAR supplement for the 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 applicant committed (Commitment No. 28) to enhance the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program before the period of extended operation as follows:

- monitor accessible structures on a frequency not to exceed 5 years, consistent with the frequency for implementing the requirements of RG 1.127
- perform periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of at least every 5 years

- include quantitative acceptance criteria for evaluation and acceptance based on the guidance provided in ACI 349.3R

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 applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, 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 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.38 Selective Leaching

Summary of Technical Information in the Application. LRA Section B.1.40 describes the new Selective Leaching Program as consistent with GALL Report AMP XI.M33, "Selective Leaching of Materials." The LRA states that the program will include a one-time visual inspection of selected components coupled with hardness measurement or other mechanical examination techniques to determine whether or not loss of material is occurring due to selective leaching.

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.M33. For the "detection of aging effects" and "corrective actions" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M33 recommends that one-time inspections using visual and hardness measurement techniques should be conducted to detect selective leaching. However, during its audit, the staff found that the applicant's Selective Leaching Program basis document states that the program will include visual inspection and hardness measurements; however, the plant-specific implementing procedure states that hardness testing or verification is conducted "where possible."

By letter dated April 25, 2012, the staff issued RAI B.1.40-1 requesting that the applicant state what methods will be used to confirm the absence of selective leaching when hardness measurements are not possible.

In its response dated May 25, 2012, the applicant stated that its Selective Leaching Program will be consistent with GALL Report AMP XI.M33, without exception. The applicant also clarified that its program will include other mechanical examination techniques such as destructive testing, chipping, or scraping when the hardness measurements are not possible.

The staff finds the applicant's response acceptable because the applicant clarified the types of examination techniques that may be used when the hardness measurements are not possible. The other mechanical examination techniques cited by the applicant are consistent with the recommendations in the GALL Report; therefore, the staff's concern described in RAI B.1.40-1 is resolved.

The "corrective actions" program element in GALL Report AMP XI.M33 recommends that unacceptable inspection findings will result in additional inspections being performed. However, during its audit, the staff found that the applicant's Selective Leaching Program basis document states that corrective actions of unacceptable inspection findings will be carried out in accordance with the CAP and that corrective actions will be consistent with the GALL Report; however, the implementing procedure states that the cause evaluation and corrective actions for indications of selective leaching should include consideration of scope expansion.

By letter dated April 25, 2012, the staff issued RAI B.1.40-2 requesting that the applicant confirm that, if selective leaching is detected in the one-time inspection proposed in the program, further inspections will be conducted to ensure that the extent of degradation is understood.

In its response dated May 25, 2012, the applicant stated that the Selective Leaching Program at GGNS is a new AMP that will be consistent with GALL Report AMP XI.M33. The applicant also cited the recommendations in the GALL Report for unacceptable inspection findings, which include a possible expansion of the inspection sample size and location and additional inspections, and stated that it will develop or revise procedures as necessary to ensure the program is consistent with GALL Report AMP XI.M33.

The staff finds the applicant's response acceptable because the applicant stated that it will develop or revise procedures to be consistent with GALL Report AMP XI.M33, including the recommendations for unacceptable inspection findings. The staff's concern described in RAI B.1.40-2 is resolved.

Based on its audit and review of the applicant's responses to RAIs B.1.40-1 and B.1.40-2, of the applicant's Selective Leaching Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M33.

<u>Operating Experience</u>. LRA Section B.1.40 does not provide any plant-specific operating experience. Instead, it states that industry operating experience will be considered when implementing the program. It also states that plant operating experience will be gained as the program is implemented during the period of extended operation and will be factored into the program via its 10 CFR Part 50, Appendix B, quality assurance program.

As discussed in the AMP Audit Report, the staff conducted an independent review of the applicant's corrective action database and confirmed that there were no plant-specific operating experience results identifying selective leaching as an aging effect. 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 industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.40 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 applicant committed (Commitment No. 29) to implement the new Selective Leaching Program prior to 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 applicant's Selective Leaching 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).

3.0.3.1.39 Service Water Integrity

Summary of Information in the Application. LRA Section B.1.41 describes the existing Service Water Integrity Program as consistent with GALL Report AMP XI.M20, "Open-Cycle Cooling Water System." The LRA states that the program manages loss of material and fouling in open-cycle cooling water systems as described in the GGNS response to GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," issued July 1989.

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.M20. For the "scope of program," "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 RAIs, as discussed below.

The "detection of aging effects" program element of GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," states, in part, that the inspection frequencies are in accordance with the applicant's docketed response to GL 89-13. SRP-LR Section A.1.2.3.4 states that, for condition monitoring programs, the frequency of inspections may be linked to plant-specific operating experience and the discussion should provide justification that the frequency is adequate to detect the aging effects before the loss of intended function. LRA Section B.1.41 states that the Service Water Integrity Program manages loss of material and fouling as described in the GGNS response to GL 89-13. The GGNS GL 89-13 response, dated January 29, 1990, states that "accessible external piping surface coatings are maintained by routine plant painting efforts." However, the GGNS GL 89-13 response does not discuss management of submerged piping. During the audit, the staff reviewed GGNS procedure 07-S-07-211, "Service Level I Coatings Condition Assessment," Section 6.0, "Frequency of Inspection," which states that the time between inspections of the pipe coating in the SSW basin will not exceed 36 months. During its review of related operating experience, the staff noted that condition reports CR-GGN-2010-05825 and CR-GNN-2010-03814 documented loss of material from submerged piping in the SSW basin ranging from 0.134 inch to 0.200 inch in 12 months. Based on the amount of material lost in 12 months, the staff questioned the adequacy of the inspection frequency of 36 months specified in the controlling procedure. By letter dated April 26, 2012, the staff issued RAI B.1.41-1 requesting the applicant to justify the 36-month inspection frequency specified in Procedure 07-S-07-211.

In its response dated May 25, 2012, the applicant stated that procedure 07-S-07-211 applies to underwater coatings in the SSW basin, including coatings on concrete structures and that the 36-month inspection frequency is appropriate for these concrete structures. The applicant also stated that in addition to the SSW basin inspections specified in procedure 07-S-07-211, it performs SSW basin piping coating inspections annually. However, the applicant did not describe where these additional inspections are specified and how the inspection frequencies are adjusted based on plant-specific operating experience. In order to address this concern, the staff issued RAI B.1.41-1a, by letter dated September 5, 2012, requesting that the applicant clarify which GGNS procedure controls the coating inspections and how the frequencies of these inspections are adjusted. The RAI also requested the applicant to update the description of the Service Water Integrity Program, since the GGNS response to GL 89-13 did not reflect the current aging management activities associated with the inspections of submerged piping in the SSW basin.

In its response dated October 2, 2012, the applicant stated that the coatings inspections are performed in accordance with GGNS 07-S-07-211 and that the inspection frequency is based on a study performed by the GGNS equipment reliability team and is specified as at least once per 12 months through the GGNS maintenance management system. The applicant also stated that the frequency is adjusted, based on documented inspection results, and would be increased for indications of accelerated corrosion to ensure unacceptable degradation does not occur prior to the next scheduled inspection. In addition, the applicant revised LRA Sections A.1.41 and B.1.41 by stating that the program includes inspections of coatings for submerged piping in the SSW basin and that the frequency of these inspections is based on previous inspection results. The staff finds the applicant’s response acceptable because it clarified which procedure controls the coatings inspections, how the inspection frequency was developed, how the inspection frequency will be adjusted, and which process specifies the coating inspection frequency. The staff considers the current 12-month frequency with adjustments for indications of accelerated corrosion to provide reasonable assurance that the effects of aging will be adequately managed. The staff’s concerns described in RAIs B.1.41-1 and B.1.41-1a are resolved.

For the “parameters monitored or inspected” program element, GALL Report AMP XI.M20 states that the program uses condition monitoring to manage corrosion. During the audit, the staff reviewed the GGNS “Strategic Plan for Open Loops,” dated 2004, which states that corrosion coupon testing and trending is performed quarterly with a target value of less than 0.005 inch per year for mild steel. The staff also reviewed GGNS procedure 08-S-03-10, “Chemistry Sampling Program,” Attachment VII, “Standby Service Water A & B,” which includes a corrosion coupon test every 6 months; however, it does not specify any control limit value. The staff noted that the corrosion coupon testing was not discussed in the LRA and was not included in the GGNS response to GL 89-13. The staff also noted that UFSAR Section 9.2.1.2 states long-term corrosion of the service water piping is compensated for by an appropriate corrosion allowance. Although corrosion coupon testing for the SSW system is being performed by the controlling procedure, it was not clear whether it is being credited as part of this program and how the target value given in the Strategic Plan for Open Loops factors into the program. By letter dated April 26, 2012, the staff issued RAI B.1.41-2 requesting the applicant to provide the bases for managing long-term corrosion of the SSW system and to clarify whether corrosion coupon testing will be included in the program.

In its response dated May 25, 2012, the applicant stated that, although a corrosion allowance was provided during the system design, the ongoing periodic visual inspections and other NDEs performed by the Service Water Integrity Program provide reasonable assurance that the SSW system pipe wall thicknesses remain acceptable. The applicant stated that GGNS performs coupon testing for information only and that it is not relied upon in the Service Water Integrity Program to manage the effects of aging. The applicant also stated that corrosion coupon testing was not an activity proposed in its response to GL 89-13. The staff finds the applicant's response acceptable because the Service Water Integrity Program performs visual and other nondestructive examinations, consistent with the GALL Report AMP, which ensures that the pipe wall thicknesses remain acceptable. The staff's concern described in RAI B.1.41-2 is resolved.

For the "detection of aging effects" program element, GALL Report AMP XI.M20 states that visual inspections are typically performed to determine whether erosion is occurring in the system. The staff noted that, although GL 89-13, Action III, recommended a routine inspection program to ensure that erosion and other problems cannot degrade the performance of the service water system, the GGNS response to GL 89-13, Action III, Item 7 "Erosion Monitoring and Control," concludes that the SSW system does not require monitoring for erosion. However, relatively recent plant-specific operating experience in condition report CR-GGN-2010-01344 discusses loss of material due to minor erosion or corrosion at the flanged connection to a discharge valve in the SSW system and proposes the inclusion of this valve in an "appropriate piping program (i.e., MS-46, Moderate Energy Piping)." The applicant provided a copy of GGNS MS-46, "Project Plan for Monitoring Internal Erosion/Corrosion in Moderate Energy Piping Components," during the audit to help clarify this issue. Although the program plan identified the SSW system as a susceptible system in the moderate energy program, it was not clear to the staff whether components in the SSW system were being managed for loss of material due to erosion/corrosion, because it is not described in the LRA nor discussed in the onsite program evaluation documentation. By letter dated April 26, 2012, the staff issued RAI B.1.41-3, requesting that the applicant clarify if the components that are being managed for loss of material by the Service Water Integrity Program are also being managed for loss of material due to erosion/corrosion through GGNS MS-46.

In its response dated May 25, 2012, the applicant stated that the "GGNS-MS-46 procedure for moderate energy piping is not an aging management program that is necessary or credited to manage the effects of aging for components that are included in the Service Water Integrity program." The response also stated that, while the cited condition report did propose inclusion of this component in inspections performed under GGNS MS-46, the associated engineering evaluation concluded that continued monitoring was not needed because the wall thickness would remain acceptable beyond the end of the period of extended operation. However, the staff noted that, in its response to RAI B.1.22-3, the applicant stated that, although the inspections described in GGNS MS-46 are not credited as part of the Flow-Accelerated Corrosion Program, the "inspections specified in GGNS MS-46 are credited as part of the AMPs for loss of material described in [the] Fire Water System and Service Water Integrity programs." In order to resolve the apparent conflicting information and to determine if SSW piping is being monitored for wall thinning due to erosion/corrosion, the staff issued RAI B.1.41-3a, by letter dated September 5, 2012, requesting that the applicant reconcile the apparent disparity between its responses to RAI B.1.22-3 and RAI B.1.41-3 and to provide information regarding all components that are being monitored for erosion/corrosion through GGNS MS-46.

In its response dated October 2, 2012, the applicant stated that site procedure GGNS MS-46 is not an AMP; however, the inspections performed by that procedure may be used as opportunistic or periodic inspections for AMPs in the LRA. The response also states that the inspections prescribed by GGNS MS-46 “are ongoing monitoring activities that are credited by aging management programs described in the GGNS LRA, such as the Fire Water System Program, the Water Chemistry Control – Closed Treated Water Systems Program, and the Service Water Integrity Program.” The staff noted an inconsistency because the LRA states that all three of the cited AMPs were consistent with the corresponding AMP in the GALL Report, and none of the three GALL Report AMPs manage loss of material due to erosion/corrosion. In addition, LRA Section A.1.41 states that the Service Water Integrity Program manages loss of material as described in the GGNS response to GL 89-13, except the GGNS GL 89-13 response states that the SSW system does not meet the criteria for erosion/corrosion monitoring. In addition, GGNS-EP-08-LRD06, “Aging Management Program Evaluation Report Non-Class 1 Mechanical” (which was provided to the staff during the staff’s onsite AMP audit), did not cite GGNS MS-46 as an implementing procedure for the three AMPs cited in the RAI response.

In order to resolve these concerns, by letter dated November 20, 2012, the staff issued RAI B.1.41-3b requesting that the applicant provide additional detail in the LRA tables such that the AMR items associated with the erosion aging mechanism are identified and to confirm that the onsite AMP evaluation documentation will be updated to include GGNS MS-46 and to update the appropriate sections of the LRA to reflect the current aging management activities that are performed by the Service Water Integrity Program. In the “Safety Evaluation Report with Open Items Related to the License Renewal of Grand Gulf Nuclear Station Unit 1,” the staff had identified the resolution of the issues documented in RAI B.1.41-3b as Open Item 3.0.3.1.39-1.

In its response dated December 18, 2012, the applicant stated that it had revised the appropriate sections of GGNS EP-08-LRD06 to identify GGNS MS-46 as an implementing procedure for monitoring microbiologically-influenced corrosion in the Fire Water System Program, the Water Chemistry Control – Closed Treated Water Systems Program, and the Service Water Integrity Program. In addition, the applicant stated that (a) GGNS MS-46 is not credited for managing loss of material due to erosion and it does not describe components that are subject to loss of material due to erosion, (b) GGNS MS-46 requires revision to update its purpose and scope because it does not reflect the systems and components that it addresses, and (c) no recent monitoring activities have been performed through GGNS MS-46.

In its review of the applicant’s response, the staff noted that the applicant’s GL 89-13 response states that the SSW does not meet the criteria for erosion monitoring; however, GGNS EP-08-LRD02, “Operating Experience Review Report (AERM),” finds that loss of material due to erosion is an aging effect requiring management for the SSW and other in-scope systems. Consequently, it was not clear to the staff how the applicant manages loss of material due to erosion, since the description of the Service Water Integrity Program only states that the program manages aging as described in the GGNS response to GL 89-13, and corresponding AMR items were not included in the LRA. In addition, it was not clear to the staff what aging management activities were being performed through GGNS MS-46, because no recent activities had been performed through GGNS MS-46 and, according to the applicant, the procedure did not reflect the systems and components that it addresses. By letter dated March 12, 2013, as modified by letter dated November 21, 2013, the staff issued RAI B.1.41-3c asking the applicant to clarify these issues.

The staff noted, in correspondence dated August 8, 2013, which was associated with a Predecisional Enforcement Conference, the applicant stated that its above response to

RAI B.1.41-3b had incorrectly stated that GGNS does not credit GGNS MS-46 for managing loss of material due to erosion. The applicant's corrective actions for the related enforcement are documented in its reply dated October 17, 2013, to the Notice of Violation.

In its response to RAI B.1.41-3c dated December 20, 2013, the applicant revised LRA Sections A.1.41 and B.1.41 to state that the Service Water Integrity Program also includes inspections for loss of material due to erosion and included a new enhancement to revise program documents to include inspections for this aging mechanism. In addition, the applicant stated that the loss of material due to erosion, which was identified in EP-08-LRD02, is being managed through a combination of AMPs, including the Service Water Integrity Program, the Periodic Surveillance and Preventive Maintenance Program, and the Flow-Accelerated Corrosion Program. As a result, the applicant added new AMR items to Tables 3.3.2-16, 3.3.2-19-1, and 3.4.2-2-9 with plant-specific notes stating that the aging effect of loss of material for the associated components is related to erosion. In addition, the applicant revised LRA Sections A.1.22 and B.1.22 for the Flow-Accelerated Corrosion Program and LRA Sections A.1.35 and B.1.35 for the Periodic Surveillance and Preventive Maintenance Program to reflect their use for managing loss of material due to erosion.

As part of its above response to RAI B.1.41-3c, the applicant provided a table with the most recent inspection results for components in the MS-46 database that are being monitored for erosion. The applicant stated that it had identified discrepancies in the MS-46 database during the development of its response to the RAI, which prevented the determination of appropriate dates for the next inspection of some components, and that this condition had been entered into the GGNS CAP. The staff noted that, although some inspections were performed in 2008, only one inspection was performed in 2012, but the majority of the inspections were conducted since August 2013.

The staff finds the applicant's response to RAI B.1.41-3c acceptable because the applicant clarified that it manages loss of material due to erosion through three different AMPs and provided additional enhancements to these programs and new AMR items that address this aging mechanism. The staff's evaluation of the enhancement to the Service Water Integrity Program is documented later in this section of the SER. The staff's evaluations of the enhancements described above to the Flow-Accelerated Corrosion Program and the Periodic Surveillance and Preventive Maintenance Program are documented in SER Sections 3.0.3.1.21 and 3.0.3.2.2, respectively. In addition, the applicant's CAP will address the discrepancies that it identified in the MS-46 database. The staff's concerns described in RAIs B.1.41-3, B.1.41-3a, B.1.41-3b, and B.1.41-3c are resolved, and Open Item 3.0.3.1.39-1 is closed.

For the "scope of program" program element, GALL Report AMP XI.M20 states that the program addresses the aging effect of material loss as described in the applicant's response to GL 89-13. The GGNS response to GL 89-13 states that, as a result of microbiological activity in the SSW system, it had implemented a Small Bore and Deadleg Pipe Inspection Program. However, the program basis documents reviewed during the audit did not discuss this program, and it was not clear whether all aspects of the program cited in the GL 89-13 response had been incorporated into the Service Water Integrity Program. By letter dated April 26, 2012, the staff issued RAI B.1.41-4 requesting that the applicant confirm that all aspects of the Small Bore and Deadleg Pipe Inspection Program have been incorporated into the Service Water Integrity Program.

In its response dated May 25, 2012, the applicant stated that the site activities referred to in its response to GL 89-13 as the "Small Bore and Deadleg Pipe Inspection Program" have been incorporated into the Service Water Integrity Program. The applicant also stated that procedure EN-DC-340, "Microbiologically Influenced Corrosion Monitoring Program," does not supplement any AMP other than the Service Water Integrity Program. The staff finds the applicant's response acceptable because the program includes the inspection activities referenced in the GGNS response to GL 89-13, which is consistent with the guidance in the GALL Report for this AMP. The staff's concern described in RAI B.1.41-4 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. In its response dated December 20, 2013, to RAI B.1.41-3c, the applicant provided an enhancement to the "detection of aging effects" program element for revising the Service Water Integrity Program documents to include inspections for loss of material due to erosion. 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 the components within the program for the appropriate aging mechanisms that the applicant identified during its operating experience reviews conducted for the LRA.

Based on reviews of LRAs and industry operating experience conducted by the staff, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letter dated January 2, 2014, the staff issued RAI 3.0.3-2 requesting that the applicant address several questions associated with managing loss of coating integrity. As a result of this RAI and follow-on RAIs, the applicant provided several enhancements to the Service Water Integrity Program in order to manage loss of coating integrity. The staff's evaluations of the changes described in these enhancements are documented in SER Section 3.0.3.3.

Based on its audit of the applicant's Service Water Integrity Program and review of the applicant's responses to RAIs B.1.41-1, B.1.41-1a, B.1.41-2, B.1.41-3, B.1.41-3a, B.1.41-3b, B.1.41-3c, and B.1.41-4, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding elements of GALL Report AMP XI.M20. The staff also reviewed the enhancement associated with the "detection of aging effects" program element, and its justification, and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.41 summarizes operating experience related to the Service Water Integrity Program. The LRA discusses a 2009 program assessment that evaluated the health of the system and the program and concluded that the performance and regulatory margin of the SSW system will be restored, once appropriate corrective actions are implemented for the longstanding structural and operational issues. The LRA also discusses a visual inspection in 2010, which detected excessive pitting and corrosion on an SSW valve body and discharge flange. The LRA states subsequent ultrasonic inspections concluded that the minimum wall thickness requirements were met. The LRA concludes by stating that the identification and evaluation of aging effects prior to loss of intended function provides evidence that the program remains effective.

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 AMP 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.

For the "operating experience" program element, SRP-LR Section A.1.2.3.10, "Operating Experience," states that operating experience should consider past corrective actions. Plant operating experience identified in condition report CR-GGN-2003-00919 describes an issue with the SSW basin siphon line, in which numerous nodules and areas of corrosion were visible on the internal surfaces of this piping and that the internal surfaces are inaccessible with respect to applying protective coatings. The condition report also states that this piping does not benefit from the water treatment program for the SSW system. The staff noted that this line is discussed in UFSAR Section 9.2.1.3, which states that the interconnecting line between the two SSW basins is required to ensure the availability of a 30-day water supply, and depending on the water level, the line either equalizes or siphons water from one basin to the other. Since the siphon function may be affected by a pin-hole leak in the upper portion of interconnecting line and given the lack of protective coatings and the lack of benefit from the water treatment program, it was not clear to the staff whether the inspections of this line would be sufficient to ensure that the effects of aging will be adequately managed such that the intended function of the siphon line will be maintained. By letter dated April 26, 2012, the staff issued RAI B.1.41-5 asking the applicant to justify the adequacy of the current inspection program for the interconnecting line between the two SSW basins for the effect that pin-hole leaks may have on the siphon function of the line and for the effect that internal nodules will have on the equalizing flow rate.

In its response dated May 25, 2012, the applicant stated that the siphon line was replaced during the spring 2012 refueling outage with super-austenitic stainless steel piping, which is not susceptible to microbiologically-influenced corrosion, and that visual inspections conducted through the Service Water Integrity Program will continue. The staff agrees that the new piping material is far more resistant to corrosion and does not require protective coatings on the submerged portions of the piping. In addition, the applicant will continue to perform the visual inspections as part of this AMP to detect loss of material that will provide reasonable assurance that the siphon line will continue to perform its intended functions. The staff's concern described in RAI B.1.41-5 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.1.41-5, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.1.41, as amended in response to RAI B.1.41-1a dated October 2, 2012, and RAI B.1.41-3c dated December 20, 2013, provides the UFSAR supplement for the Service Water 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 applicant committed (Commitment No. 35) to enhancing the program by revising Service Water Integrity Program documents to include inspections for loss of material due to erosion. The staff finds that the information in the UFSAR supplement, as amended by letters dated October 2, 2012, and December 20, 2013, is an adequate summary description of the program. In addition, the staff's

evaluation of the UFSAR changes to address loss of coating integrity is documented in SER Section 3.0.3.3.

Conclusion. On the basis of its audit and review of the applicant's Service Water Integrity Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 35 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.40 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.42 describes the existing Structures Monitoring Program as consistent, with enhancements, with GALL Report AMP XI.S6, "Structures Monitoring." The Structures Monitoring Program is an existing program that provides for aging management of structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, and NUMARC 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at 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 one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S6. For the "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 "detection of aging effects" program element in GALL Report AMP XI.S6 recommends that in general all structures be monitored at a frequency not to exceed 5 years (e.g., structures exposed to natural environments, structures inside primary containment, continuous fluid-exposed structures, and structures retaining fluid or pressure). The GALL Report also notes that some structures of lower safety significance and subjected to benign environmental conditions may be monitored at an interval exceeding 5 years; however, they should be identified and listed together with their operating experience. The GALL Report recommends that for plants with non-aggressive groundwater or soil, the acceptability of inaccessible areas should be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. During its audit, the staff found that the applicant's Structures Monitoring Program notes that inspection frequency is every 5 years for high-risk significant structures and 10 years for low-risk significant structures, with provisions for more frequent inspections to ensure that observed conditions that have the potential to affect the intended functions are evaluated or corrected in accordance with the corrective action process. The LRA AMP basis document also states that for high radiation areas, operationally sensitive areas inaccessible due to congestion, portions of structures that are underground or underwater, concealed by the presence of other permanent structures, or that cannot be safely inspected without an extraordinary expenditure of plant resources do not need to be inspected. Furthermore, the reason for not inspecting these structures is to be recorded. The LRA AMP further notes that inspections of inaccessible areas will be performed in environments where observed conditions in accessible areas exposed to the same environment indicate significant degradation is occurring. The staff is uncertain that the inspection frequency for all structures is in compliance with industry standards on inspection frequency (e.g., as noted in ACI 349.3R-96) or what conditions in accessible areas will result in inspections of inaccessible areas. By letter dated May 3, 2012, the staff issued RAI B.1.42-1 requesting that the applicant: (1) provide information to confirm that the inspection frequency criteria identified in the Structures Monitoring Program and criteria identified in industry standards (e.g., as noted in ACI 349.3R-96) are aligned, or provide justification for not meeting the industry-recommended inspection frequency; and (2) provide information to confirm that criteria in the Structures Monitoring Program relative to inspection requirements for inaccessible areas and criteria in GALL Report AMP XI.S6 are aligned.

In its response dated May 30, 2012, the applicant responded to part (1) of RAI B.1.42-1 by stating that ACI 349.3R-96, Chapter 6 states in part that “the frequency at which periodic inspections are conducted within the evaluation procedure should be defined by the plant owner. Frequencies should be based on the aggressiveness of environmental and physical conditions of the plant structures.” The applicant also stated that an enhancement identified in LRA Section B.1.42 will require inspections every 5 years for structures and structural components within the scope of license renewal unless technical justification is provided to extend the inspection interval to 10 years. The applicant further stated that this enhancement will ensure that in-scope structures are inspected at least once every 10 years during the period of extended operation.

Based on its review, the staff finds additional information is needed to ensure that structures and structural components, within the scope of the Structures Monitoring Program, are inspected at an inspection frequency consistent with the GALL Report recommendations. It is not clear to the staff which structures and structural components are inspected at a frequency of 10 years and what technical justification (e.g., safety significance, environmental conditions, and operating experience) has been used to identify these structures and structural components.

By letter dated July 27, 2012, the staff issued RAI B.1.42-1a asking the applicant to clarify if all structures and structural components, within the scope of license renewal, will be inspected every 5 years, and if there are structures and structural components that will be inspected at a frequency greater than the 5-year interval, to identify and list the structures and structural components, and provide technical justification for the inspection frequency.

In its response dated August 23, 2012, the applicant stated that, consistent with recommendations in the GALL Report, GGNS structures and structural components within the scope of license renewal will be inspected every 5 years during the period of extended operation. The applicant further stated that GGNS has not identified any structures or structural components within the scope of license renewal that will be inspected at a frequency of less than once every 5 years during the period of extended operation.

Based on its review, the staff finds the applicant’s response acceptable because the applicant has clarified that inspections will be performed every 5 years for structures and structural components within the scope of license renewal. Additionally, the applicant has revised the UFSAR supplement and the Structures Monitoring Program enhancement to clarify that the inspection frequency is consistent with recommendations in GALL Report AMP XI.S6. The staff’s concern described in RAI B2.1.42-1a is resolved.

In its response dated May 30, 2012, the applicant responded to part (2) of RAI B.1.42-1 by stating that the groundwater is non-aggressive (chloride less than 500 ppm, sulfates less than 1,500 ppm, and pH greater than 5.5) and periodic sampling, testing, and analyzing of the groundwater will be done at least once every 5 years. The applicant also stated that if normally inaccessible areas become accessible due to required plant activities, an inspection of these areas will be conducted. The applicant further stated that inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring that could lead to loss of structural integrity.

Based on its review, the staff finds the applicant's response acceptable because the groundwater will be monitored at a frequency not to exceed 5 years, the 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, and representative samples of exposed portions of below-grade concrete will be examined when excavated for any reason. These inspection criteria for inaccessible areas, therefore, are consistent with the criteria in GALL Report AMP XI.S6. The staff's concern described in RAI B.1.42-1, part (2), is resolved.

The "acceptance criteria" program element in GALL Report AMP XI.S6 recommends ACI 349.3R-96 as providing an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes. It also notes that the plant-specific structures monitoring programs are to contain sufficient detail or acceptance criteria to conclude that this program attribute is satisfied. However, during its audit, the staff found that the applicant's Structures Monitoring Program noted that it will be enhanced to prescribe acceptance criteria considering information provided in industry codes, standards, and guidelines, including NEI 93-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-96. A review of Program Basis Documentation indicated that a yes-no check list is used to provide Tier One acceptance criteria corresponding to Section 5.1 of ACI 349.3R-96; however, this acceptance criteria does not correspond to the quantitative surface condition criteria for cracking, popouts and voids, and spalling provided in ACI 349.3R-96. By letter dated May 3, 2012, the staff issued RAI B.1.42-2 requesting the applicant to provide quantitative acceptance criteria to demonstrate that acceptance criteria in the Structures Monitoring Program meet the Tier One, Tier Two, and Tier Three Criteria recommended by the GALL Report AMP, or if not committing to ACI 349.3R-96 and electing to use plant-specific criteria, provide a technical basis for deviations from criteria specified in ACI 349.3R-96.

In its response dated May 30, 2012, the applicant stated that the acceptance criteria of the Structures Monitoring Program, with enhancements, align with the criteria provided in GALL Report AMP XI.S6 criteria. The applicant also stated that the Structures Monitoring Program recording criteria, identified on specific inspection forms as Yes-No response, align with "first-tier" criteria from Section 5.1 of ACI 349.3R-96 with a positive response indicating that the findings are within first-tier criteria of ACI 349.3R-96 and thus are "acceptable," and no further action is warranted; however, a no response invokes "second-tier" criteria that use criteria provided in Section 5.2 of ACI 349.3R-96. The applicant further stated that if the responsible engineer determines that the "second-tier" criteria are exceeded, further technical evaluations result, which is consistent with "tier-three" criteria in ACI 349.3R-96.

The staff finds the applicant's response acceptable because acceptance criteria of the Structures Monitoring Program use a three-tier approach that is consistent with that provided in

ACI 349.3R-96, and, therefore, is consistent with GALL Report AMP XI.S6 acceptance criteria. The staff's concern described in RAI B.1.42-2 is resolved.

The staff also 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.1.42 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that: (1) the following in-scope structures and structural components will be included in the AMP: GGNS containment building, control house-switchyard, culvert No. 1 and drainage channel, manholes and duct banks, and radioactive waste building pipe tunnel, as well as a number of other in-scope structural components specifically identified in the LRA AMP; (2) "significant degradation" is clarified to include the following: "that could lead to loss of structural integrity"; and (3) guidance will be included to perform periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of at least every 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, the "scope of program" program element will clearly identify all structures, structural components, component supports, and structural commodities in the scope of the program; it will clarify the meaning of "significant degradation"; and it will include guidance to perform periodic sampling and analysis of groundwater, consistent with recommendations in the GALL Report AMP.

Enhancement 2. LRA Section B.1.42 states an enhancement to the "parameters monitored or inspected," program element. In this enhancement, the applicant stated that: (1) inspections will be conducted for missing nuts for the structural connections; (2) sliding and bearing surfaces such as lubrite plates will be monitored for loss of material due to wear or corrosion, debris, or dirt; and (3) elastomeric vibration isolators and structural sealants will be monitored for cracking, loss of material, and hardening. 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, the parameters monitored for these components will be consistent with those identified in the GALL Report AMP.

Enhancement 3. LRA Section B.1.42 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that: (1) inspection requirements for vibration isolators will include augmented inspections by feel or touch to detect hardening, if the vibration isolation function is suspect; and as amended by letter dated August 23, 2012, and (2) inspections will be required every 5 years for structures and structural components within the scope of license renewal. The staff reviewed this revised enhancement against the corresponding program element in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the "detection of aging effects" program element will be consistent with GALL Report AMP XI.S6.

Enhancement 4. LRA Section B.1.42 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that program acceptance criteria will be prescribed based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-96, and that industry and plant-specific operating experience also will be considered in the development of the acceptance criteria. 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 the acceptance criteria will be consistent with those identified in the GALL Report AMP.

Summary. Based on its audit, and review of the applicant's responses to RAIs B.1.42-1, B.1.42-1a, and B.1.42-2 of the applicant's Structures Monitoring Program, the staff finds that program elements one through six 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 the "scope of program," "parameters monitored or inspected," "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.1.42 summarizes operating experience related to the Structures Monitoring Program. During a 2007 inspection, Door 1M112 at the SSW valve room would not completely open due to vertical settlement in the area. A review of the applicable design calculation indicated that vertical settlement was not an issue for the shield wall, although it could interfere with the ability to use the door; therefore, an engineering change was prepared to allow removal of concrete in the area that the door was rubbing. The applicant also described an instance when there was water leaking in the reactor water cleanup (RWCU) heat exchanger room from a crack in the ceiling identified in 2007, which previously had been identified in 1987. Samples were taken and results indicated that no corrosion was occurring. The RWCU heat exchanger room was found to be structurally adequate. The applicant stated that these examples illustrating identification of degradation and corrective action before loss of intended function provide evidence that the program is effective for managing aging effects for structural components.

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 AMP 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 RAIs, as discussed below.

During a walkdown of the auxiliary building, a crack was observed in the south stairwell exterior concrete wall that was noted to run from about 228 feet elevation to about 166 feet elevation. The crack width was on the order of 0.01 inch with some locations along the crack length exhibiting chipping. Plant personnel were uncertain whether the crack extended completely through the exterior concrete wall and stated that exterior monitoring of the concrete surface was done from lower elevations using binoculars. The staff was concerned that the applicant's visual resolution capability used during visual inspections may not be consistent with that recommended in Section 3.5, "Evaluation Techniques," of ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," which describes that the scope of the visual examinations of structures should include all exposed surfaces of the structure; joints and joint material; interfacing structures and materials, such as abutting soil; embedments; and attached components, such as base plates and anchor bolts; and that these components should be directly viewed (maximum 600 mm focal distance), and photographs or video images taken of all discontinuities, defects, and significant findings, if possible. Section 3.5 of ACI 349.3R-96 also notes that direct viewing can require the installation of temporary ladders, platforms, or scaffolding and use of binoculars, fiberscopes, and other optical aids is recommended if necessary to gain better access, augment the inspection, or further examine discontinuities. Furthermore, such equipment should have suitable resolution capabilities under ambient or enhanced lighting. Also, Table IWA-2211-1, "Visual Examinations," of Section XI of the ASME Boiler and Pressure Vessel Code identifies a maximum direct examination distance of 2 feet for VT-1 examinations. The staff is uncertain that visual resolution capability is being used during visual examinations of structures.

By letter dated May 3, 2012, the staff issued RAI B.1.42-3 requesting that the applicant provide information to verify that sufficient visual resolution capability is being used during visual examinations of structures to detect and quantify forms of degradation that can potentially affect intended functions of the structures.

In its response dated May 30, 2012, the applicant stated that the Structures Monitoring Program uses visual inspections to detect and quantify the extent of degradation and requires use of appropriate tools such as feeler gages, tape measures, flashlights, cameras, and binoculars during the inspections. The applicant also stated that the Structures Monitoring Program will be enhanced to: (1) require direct visual examination when observations can be made within 24 inches of the surface to be examined and at an angle not less than 30 degrees to the surface, and may incorporate mirrors to improve the angle of vision and accessibility in constricted areas; and (2) specify use of remote visual examination (e.g., optical aids such as telescopes, borescopes, fiber optics, cameras, and other suitable instruments) to substitute for direct examination, provided such systems have a resolution capability as least equivalent to that attainable by direct visual examination.

Based on its review, the staff finds the applicant's response acceptable because the Structures Monitoring Program, after enhancements related to direct and remote visual inspections, will be consistent with recommendations provided in industry codes, standards, and guidelines such as provided in Section 3.5.1 of ACI 349.3R-96. The staff also confirmed that the applicant through Commitment No. 30 will enhance the "detection of aging effects" program element of the Structures Monitoring Program to implement these enhancements before November 1, 2024. The staff's concern described in RAI B.1.42-3 is resolved.

During a walkdown of the auxiliary building, water leakage was observed near stair 1T02 (elevation 93 feet), apparently resulting from groundwater infiltration from ineffective or degraded expansion or isolation joints between the turbine building and the auxiliary building. It was also noted on several surfaces in this area that rust colored stains were present. Since Plant Basis Documentation has identified this as a continuing problem, it is unclear to the staff how the Structures Monitoring Program, or other plant-specific aging program, will address the leakage to ensure that aging effects, especially in inaccessible areas and plant internal steel components exposed to groundwater leakage, will be effectively managed to ensure that there is no loss of intended function. By letter dated May 3, 2012, the staff issued RAI B.1.42-4 requesting that the applicant provide information on how the in-leakage of groundwater will be addressed under the CAP.

In its response dated May, 30, 2012, the applicant stated that the in-leakage of groundwater has been addressed through the site corrective action process that resulted in implementation of corrective actions. Corrective action includes guidance on sealing the locations where in-leakage is identified, either in the construction joints or cracks of the structures. As an additional protective measure, ground floor slabs have been coated, including attachments, to minimize the effects of in-leakage of groundwater on concrete and steel structures. The applicant also stated the in-building leakage source, in the stairwell of the turbine building and auxiliary building, was determined to be construction joints where water stop seals may have degraded. A condition report was initiated and an evaluation was performed determining that the liquid was clear without indication of iron oxides that would be present if corrosion of the concrete steel reinforcement was occurring, the cracks were not sufficient to impact the building structural integrity, and the area has been sealed against further in-leakage. The applicant further stated that monitoring of external SC surfaces during walkdowns to identify degraded conditions, such as the water in-leakage noted and the corrective action process will be effective in managing aging during the period of extended operations.

The staff finds the applicant's response acceptable because it was demonstrated that conditions such as in-leakage of groundwater, which can lead to SC degradation, will be identified during walkdowns (e.g., presence of rust staining on internal plant steel components and presence of iron oxides in groundwater indicating degradation of steel reinforcement of inaccessible concrete areas) and corrective actions were initiated to seal the area against further in-leakage, before loss of intended function(s). The staff's concern described in RAI B.1.42-4 is resolved.

During the breakout session for the Structures Monitoring Program, the staff asked: (1) if historical data on leakage of the spent fuel pool are available; (2) if leakage is present, is the leakage confined to the leak-chase system; and (3) if leakage is not present, is the leak-chase system routinely inspected to verify that it is clear. This information was not available during the breakout session, so the staff is uncertain if leakage of the spent fuel pool is occurring, and if leakage is present, that it is being confined to the leak-chase system.

By letter dated May 3, 2012, the staff issued RAI B.1.42-5 requesting that the applicant provide: (1) historical data on spent fuel pool leakage obtained by monitoring the leak-chase system and note whether or not the leakage is confined to the leak-chase system; (2) if the leakage is not confined to the leak-chase system, identify any structures or structural components potentially affected and any plans to address the leakage; and (3) if no leakage has been reported, provide inspection results, or plans for inspection of the leak-chase system, to demonstrate that the leak-chase system is not blocked.

In its response dated May 30, 2012, the applicant stated that leakage from the upper containment pool is monitored daily and from the spent fuel pool weekly, with two incidences of leakage from the upper containment pool noted that have been contained in the leak chase system and therefore have not affected structures. The applicant also noted that leakage from the pools will be monitored periodically during the period of extended operation with trending and leakage through the tell-tale drains used as an indicator that drainage through the leak chase is occurring and that the tell-tale drains are not blocked and are performing as designed. The applicant further noted in order to confirm that no significant blockage of the tell-tale drains has occurred, the Structures Monitoring Program will be enhanced to periodically inspect the leak chase system associated with the upper containment pool and spent fuel pool, and concrete surfaces will be inspected for degradation where leakage has been observed.

The staff finds the applicant's response acceptable because the leakage from the upper containment pool has been identified and noted to be confined to the leak-chase system and there is no evidence that it has affected other structures or components, upper containment pool and spent fuel pool leakage is periodically monitored, and the Structures Monitoring Program will be enhanced to periodically inspect the leak-chase system associated with the upper containment pool and spent fuel pool to ensure the tell-tale drains are free of significant blockage. The staff also confirmed that the applicant, through Commitment No. 30, will enhance the "parameters monitored or inspected" program element of the Structures Monitoring

Program to implement the enhancement before November 1, 2024. The staff's concern described in RAI B.1.42-5 is resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs B.1.42-3, B.1.42-4, and B.1.42-5, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.42 provides the UFSAR supplement for the Structures 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 3.0-1. The staff also noted that the applicant committed (Commitment No. 30) to enhance the Structures Monitoring Program prior to May 1, 2024, to:

- clarify the in-scope structures and structural components
- clarify the term "significant degradation" to include the following: "that could lead to loss of structural integrity"
- include guidance to perform periodic sampling and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of at least once every 5 years
- include an inspection for missing nuts for the structural connections
- include monitoring of sliding and bearing surfaces, such as lubrite plates, for loss of material due to wear or corrosion, debris, or dirt. The program will be enhanced to include monitoring elastomeric vibration isolators and structural sealants for cracking, loss of material, and hardening
- include periodically inspecting the leak-chase system associated with the upper containment pool and spent fuel pool to ensure the tell-tale drains are free of significant blockage. The inspection will also inspect concrete surfaces for degradation where leakage has been observed in accordance with this program
- inspection requirements for vibration isolators will be enhanced to include augmented inspections by feel or touch to detect hardening, if the vibration isolation function is suspect
- require inspections every 5 years for structures and structural components within the scope of license renewal
- require direct visual examinations when access is sufficient for the eye to be within 24 inches of the surface to be examined and at an angle of not less than 30 degrees to the surface. Mirrors may be used to improve the angle of vision and accessibility in constricted areas.
- specify that remote visual examination may be substituted for direct examination. For all remote visual examinations, optical aids such as telescopes, borescopes, fiber optics, cameras, or other suitable instruments may be used provided such systems have a resolution capability at least equivalent to that attainable by direct visual examination
- prescribe acceptance criteria based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-96. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria

The staff finds that the information in the UFSAR supplement, as amended by letters dated July 3, 2012, and August 23, 2012, and is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's 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 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.41 Water Chemistry Control – BWR

Summary of Technical Information in the Application. LRA Section B.1.43 describes the existing Water Chemistry Control – BWR Program as consistent with GALL Report AMP XI.M2, "Water Chemistry." The LRA states that this program uses the EPRI water chemistry guidelines to manage loss of material, cracking, and fouling by monitoring and controlling water chemistry. The LRA also states that the One-Time Inspection Program verifies the effectiveness of the Water Chemistry Control – BWR Program through inspections or non-destructive evaluations of representative samples.

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.M2. For the "parameters monitored or inspected" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "parameters monitored or inspected" program element in GALL Report AMP XI.M2 recommends maintaining water quality in accordance with the EPRI water chemistry guidelines, which for BWRs is EPRI 1016579, BWRVIP-190. However, during the audit, the staff noted that the applicant's controlling procedure 01-S-08-29, "EPRI Water Chemistry Guidelines," does not specify the parameter for electrochemical corrosion potential (ECP) as contained in BWRVIP-190, Table 6-5, for reactor water power operation with hydrogen water chemistry (HWC). In addition, the applicant's procedure 08-S-03-10, "Chemistry Sampling Program," specifies a control limit for zinc, which is consistent with BWRVIP-190 for noble metal chemical application (NMCA), but the LRA did not indicate that GGNS was using NMCA. The staff also noted that BWRVIP-190 states that the basis for inspection relief for BWR internals based strictly on environmental considerations is documented in BWRVIP-62, "Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection." However, the staff could not confirm whether the applicant has met all of the conditions in the staff's SE of BWRVIP-62. By letter dated April 26, 2012, the staff issued RAI B.1.43-1, requesting the applicant to confirm the method of controlling HWC in the RV, and to confirm whether NMCA plus hydrogen is being used. The staff also requested that the applicant confirm whether all of the conditions in the staff's SE for BWRVIP-62 are met and to provide the method of determining the effectiveness of HWC at the site.

In its response dated May 25, 2012, the applicant stated that HWC is controlled using FW hydrogen injection in conjunction with online NMCA. The applicant also stated that continuous

ECP monitoring will be installed during the spring 2012 outage, which will meet the recommendations of BWRVIP-62, Revision 1. The applicant further stated that the effectiveness of HWC is determined through: (a) monitoring ECP, (b) monitoring FW hydrogen flow, (c) maintaining the hydrogen-to-oxygen molar ratio greater than or equal to 2 in non-monitored locations when determined by the BWR Vessel and Internals Application radiolysis model, and (d) removing an artifact from the reactor core to measure platinum loading. The applicant also stated that BWRVIP-62, Revision 1, does not require platinum deposition measurements on coupons for plants using online noble metals chemistry to demonstrate mitigation.

The staff finds the applicant's response partially acceptable because the applicant clarified that it uses online NMCA and FW hydrogen injection to control HWC, and that, pending confirmation that the ECP probes were installed and except as noted below, it confirms the effectiveness of HWC consistent with the EPRI water chemistry guidelines and meets the recommendations in BWRVIP-62. However, the staff noted that BWRVIP-62, Revision 1, has not been reviewed by the NRC, and that there are differences between this revision and the previous revision regarding verification of noble metal loading. Specifically, the revision that the staff accepted states that noble metal (platinum) loading shall be monitored by periodic removal of durability monitors or by removal and analysis of deposits from artifacts within the vessel. In addition, BWRVIP-190, Table 2-5, states that the catalyst loading (platinum deposition) is one of the two primary parameters to be monitored to demonstrate HWC effectiveness. In its response to RAI B.1.43-1, the applicant stated that it had removed an artifact to measure platinum loading; however, the applicant also stated that BWRVIP-62, Revision 1, does not require deposition measurements. It is not clear to the staff whether the applicant will continue to monitor noble metal loading during the period of extended operation or whether continuous ECP monitoring has been installed. By letter dated August 15, 2012, the staff issued RAI B.1.43-1a requesting the applicant to confirm that it will continue to monitor catalyst loading as specified by BWRVIP-190 or to provide justification otherwise. The staff also requested that the applicant confirm that continuous ECP monitoring had been installed.

In its response dated September 13, 2012, the applicant stated that it completed the installation of the equipment for continuous ECP monitoring during the spring 2012 refueling outage. The applicant also stated that noble metal loading will be monitored using periodic removal of durability monitor coupons, during the period of extended operation. The staff finds the response acceptable because the applicant has installed continuous ECP monitoring and will monitor catalyst loading as specified by BWRVIP-190, which ensures that water chemistry parameters are being maintained to mitigate applicable aging effects consistent with the EPRI water chemistry guidelines recommended in GALL Report AMP XI.M2. The staff's concerns described in RAI B.1.43-1a are resolved.

Based on its audit of the applicant's Water Chemistry Control – BWR Program and review of the applicant's response to RAI B.1 43-1, the staff finds that program elements 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.1.43 summarizes operating experience related to the Water Chemistry Control – BWR Program. The LRA discusses an evaluation required by SOER 03-02, which upgraded and confirmed the effectiveness of the water chemistry program. The LRA also described the condition reports that were initiated due to adverse trends in water chemistry parameters and the corrective actions taken to prevent the parameters from reaching unacceptable values. In addition, the LRA discusses the addition of an advanced resin cleaning system for the condensate resins and the management of condensate temperatures in cold weather to improve iron removal. The LRA states that the identification of program enhancements and corrective actions provides assurance that the program will remain effective for managing aging effects.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.43 provides the UFSAR supplement for the Water Chemistry Control – BWR 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 EPRI water chemistry guidelines, it did not state that the program is based on BWRVIP-190. The staff determined that the licensing basis for this program may not be adequate if the applicant does not incorporate this information into its UFSAR supplement. By letter dated April 26, 2012, the staff issued RAI B.1.43-2 requesting the applicant to provide information showing that a reference to the specific EPRI water chemistry guideline was not required or to revise Section A.1.43 to refer to a specific version of the EPRI water chemistry guideline.

In its response dated May 25, 2012, the applicant revised LRA Section A.1.43 to include reference to BWRVIP-190. The staff finds the applicant's response acceptable because the applicant has revised the UFSAR supplement to include the specific EPRI guideline upon which the program is based. 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.1.43-2 is resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated May 25, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Control – BWR 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.M2. 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).

3.0.3.1.42 Water Chemistry Control – Closed Treated Water Systems

Summary of Technical Information in the Application. LRA Section B.1.44 describes the existing Water Chemistry Control – Closed Treated Water Systems Program as consistent, with enhancements, with GALL Report AMP XI.M21A, "Closed Treated Water Systems." The LRA states that the AMP manages loss of material, cracking, and fouling in components exposed to a treated water environment. The LRA also states that the AMP proposes to manage these aging effects through monitoring and control of water chemistry as well as visual inspections.

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.M21A. For the "scope of program," "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 RAIs, as discussed below.

The "scope of program" program element in GALL Report AMP XI.M21A recommends that this program manages aging effects of components fabricated from any material and exposed to treated water, but the program does not include systems managed by another AMP. During its audit, the staff found that the applicant's documentation for its GL 89-13 Service Water Integrity Program stated that the GL 89-13 program is also applied to closed cooling loops, due to the potential for in-leakage, inadequate chemistry controls, or aging that may have occurred before current chemistry controls became active. The staff noted that GL 89-13 program activities were not included in documentation of the applicant's Water Chemistry Control – Closed Treated Water Systems Program. By letter dated April 26, 2012, the staff issued RAI B.1.44-3 requesting that the applicant state what aging management activities associated with the applicant's GL 89-13 Service Water Integrity Program are applied to systems managed by the Water Chemistry – Closed Treated Water Systems Program and what, if any, operating experience prompted the use of the GL 89-13 program activities for closed cooling loops.

In its response dated May 25, 2012, the applicant stated that there are no systems at GGNS that are part of the service water system that meet the GL 89-13 definition of a closed-cycle system, and thus no activities associated with the Service Water Integrity Program are applied to any closed-cycle treated water cooling systems. The applicant also stated that the reference to closed-loop cooling systems is included in the Entergy fleet GL 89-13 Service Water Program document since they may be present at other Entergy facilities.

The staff finds the applicant's response acceptable because the applicant clarified that the scope of the Water Chemistry Control – Closed Treated Water Systems Program is fully defined in the LRA and the applicant's onsite documentation of this program, and there are no applicable activities associated with the applicant's GL 89-13 Service Water Program. The staff's concern described in RAI B.1.44-3 is resolved.

The "parameters monitored or inspected" program element in GALL Report AMP XI.M21A recommends that the acceptable range of water chemistry parameters be in accordance with industry standard guidance, such as those described in EPRI Technical Report 1007820. However, during its audit, the staff was not able to confirm that the applicant's Water Chemistry Control – Closed Treated Water Systems Program maintains water chemistry in closed treated water systems in accordance with EPRI guidelines. The staff noted that deviations in the applicant's program from EPRI guidelines included missing control limits and control limits with undefined action levels. By letter dated April 26, 2012, the staff issued RAI B.1.44-1 requesting that the applicant provide an enhancement to the Water Chemistry Control – Closed Treated Water Systems Program to align the plant's water chemistry controls with the EPRI guidance or justify that the deviations will not adversely affect corrosion mitigation.

In its response dated May 25, 2012, the applicant revised LRA Sections A.1.44 and B.1.44 to include an enhancement to align the water chemistry control parameter limits for closed treated water systems with those of EPRI 1007820.

The staff finds the applicant's response acceptable because the applicant's enhancement to the Water Chemistry Control – Closed Treated Water Systems Program will maintain water chemistry consistent with the industry standard guidance in EPRI Technical Report 1007820, which is consistent with GALL Report guidance and provides assurance that corrosion will be effectively mitigated during the period of extended operation. The staff's concern described in RAI B.1.44-1 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," "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.1.44 states an enhancement to the "scope of program" and "preventive actions" program elements. In this enhancement, the applicant stated that the program will be enhanced to provide a corrosion inhibitor for the engine jacket water on the engine-driven fire water pump diesels in accordance with industry guidelines and vendor recommendations. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because the addition of corrosion inhibitors is consistent with the "preventive actions" program element of GALL Report AMP XI.M21A and, when the enhancement is implemented, the corrosion inhibitor will be capable of mitigating loss of material due to corrosion such that the function of the jacket water system is maintained.

Enhancement 2. LRA Section B.1.44 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that the program will be enhanced to provide periodic flushing of the engine jacket water and cleaning of the heat exchanger tubes for the engine-driven fire water pump diesels in accordance with industry guidelines and vendor recommendations. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because, although GALL Report AMP XI.M21A does not specify flushing and cleaning of closed cooling systems, these activities, in addition to water chemistry monitoring, are capable of ensuring that the jacket water chemistry remains within specifications for cooling and corrosion control and heat transfer properties are maintained.

Enhancement 3. LRA Section B.1.44 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to provide testing of the engine jacket water for the engine-driven fire water pump diesels at least once per refueling cycle. However, the staff noted that GALL Report AMP XI.M21A recommends that water testing intervals should be in accordance with the selected industry standard, but in no case should the testing interval be greater than quarterly, unless justified. The staff also noted that the guidelines in EPRI Technical Report 1007820 state that water chemistry monitoring of intermittently used closed cooling systems be performed monthly or as operated. EPRI Report 1007820 has an exception for glycol-based systems, in which case the recommended testing interval is quarterly (Tier 1 systems) or annually (Tier 2 systems). By letter dated April 26, 2012, the staff issued RAI B.1.44-2 requesting that the applicant justify why testing of the jacket water once per refueling cycle is adequate to ensure that the ability of the water chemistry to mitigate corrosion will be maintained or to revise the testing frequency to be consistent with the EPRI guidelines.

In its response dated May 25, 2012, the applicant revised LRA Sections A.1.44 and B.1.44 to state that the fire water pump diesel jacket water will be tested annually, consistent with EPRI 1007820 guidelines.

The staff finds the applicant's response acceptable because the annual testing of the engine jacket water for the fire water pump diesels is consistent with the GALL Report and EPRI guidelines for intermittently used glycol-based Tier 2 closed cooling water systems, which provides assurance that corrosion will be effectively mitigated during the period of extended operation. The staff noted that the glycol chemistry of the engine jacket water was confirmed during the staff's audit of the Water Chemistry Control – Closed Treated Water Systems Program. The staff's concern described in RAI B.1.44-2 is resolved.

Enhancement 4. LRA Section B.1.44, as revised by the applicant's response to RAI B.1.44-1 dated May 25, 2012, states an enhancement to the "parameters monitored or inspected" and "acceptance criteria" program elements. In this enhancement, the applicant stated that the program will be enhanced to revise the water chemistry procedure for closed treated water systems to align the water chemistry control parameter limits with those of EPRI 1007820. 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 ensure that the specific water chemistry parameters monitored and the acceptance range of values for these parameters will be in accordance with EPRI Technical Report 1007820, which is consistent with the GALL Report guidance for effective mitigation of loss of material, cracking, and fouling.

Enhancement 5. LRA Section B.1.44 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to conduct inspections whenever a boundary is opened for the systems managed by the Water Chemistry Control – Closed Treated Water Systems Program. The applicant also stated that the inspections will be conducted in accordance with applicable ASME codes, industry standards, and plant-specific inspection procedures that are capable of detecting corrosion or cracking. 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, the opportunistic inspections, along with the 10-year inspection periodicity documented below in Enhancement 6, will be capable of detecting degradation prior to loss of intended function, consistent with the "detection of aging effects" program element of GALL Report AMP XI.M21A.

Enhancement 6. LRA Section B.1.44 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to conduct inspections on a representative sample of piping and components at a frequency of once every 10 years for the systems managed by the Water Chemistry Control – Closed Treated Water Systems Program. The applicant also stated that the inspection sample will be 20 percent of each material/environment/aging effect combination (with a maximum of 25 components) and will focus on locations with the highest likelihood of corrosion or cracking. The applicant further stated that the inspections will be conducted in accordance with applicable ASME Codes, industry standards, and plant-specific inspection procedures that are capable of detecting corrosion or cracking. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because the inspections described here, in addition to the opportunistic inspections described above in Enhancement 5, will be capable of detecting degradation prior to loss of intended function, consistent with the "detection of aging effects" program element of GALL Report AMP XI.M21A.

Summary. Based on its audit, and review of the applicant's responses to RAIs B.1.44-1, B.1.44-2, and B.1.44-3 of the applicant's Water Chemistry Control – Closed Treated Water Systems Program, the staff finds that program elements one through six 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 "scope of program," "preventive actions," "parameters monitored or inspected," and "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.1.44 summarizes operating experience related to the Water Chemistry Control – Closed Treated Water Systems Program. The applicant stated that, from 2008 to 2010, several condition reports were initiated due to adverse trends in parameters monitored by the program and that timely corrective actions were taken to preclude reaching unacceptable values. As discussed in the AMP Audit Report, the staff reviewed several of these condition reports related to the maintenance of water chemistry to confirm this information in the LRA.

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 AMP 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 implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.44 provides the UFSAR supplement for the Water Chemistry Control – 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 applicant committed (Commitment No. 31) to implement the enhancements to the program prior to 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 applicant's Water Chemistry Control – 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 through Commitment No. 31 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as plant-specific:

- 115 kV Inaccessible Transmission Cable
- Periodic Surveillance and Preventive Maintenance

For AMPs not consistent with or not addressed in the GALL Report, the staff performed a complete review to determine their adequacy to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in the following sections.

3.0.3.2.1 115 kV Inaccessible Transmission Cable

Summary of Technical Information in the Application. LRA Section B.1.1 describes the new 115 kV Inaccessible Transmission Cable Program as plant specific. The applicant stated that the 115 kV Inaccessible Transmission Cable Program is a new condition monitoring program that will manage the effects of aging on the 115 kV inaccessible transmission cables. In this program, inaccessible transmission cables will be tested to provide an indication of the condition of the cable insulation properties. The specific type of test will be a proven test for detecting deterioration of the cable insulation. The applicant also stated that this program will be implemented before the period of extended operation, and the first cable tests and manhole inspections are to be completed prior to the period of extended operation.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows. The staff's review of the "corrective actions," "confirmation process," and "administrative controls" program elements are documented in SER Section 3.0.4.

Scope of Program. LRA Section B.1.1 states that this program applies to inaccessible underground (e.g., in conduit, duct banks, or direct buried) transmission cables (115 kV) within the scope of license renewal that are exposed to significant moisture. The LRA defines significant moisture as periodic exposure to moisture that lasts more than a few days (e.g., cable wetting or submergence in water). The following cables are included in the scope of this program:

- ESF 12 Feeder - 115 kV Switchyard to Overhead Power Pole: Phases A, B, & C (2 cables per phase)

The staff reviewed the applicant's "scope of program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the scope of program should include the specific SCs, the aging of which the program manages. The staff noted that the specific commodity groups for which the program manages aging effects are identified (ESF 12 feeder – 115 kV switchyard to overhead power poles: phases A, B, and C), which satisfies the criterion defined in SRP-LR Appendix A.1.2.3.1.

The staff finds the applicant's "scope of program" program element to be adequate because the specific SCs for which the program manages aging effects are identified.

Based on its review of the application, the staff confirmed that the "scope of program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

<u>Preventive Actions</u>. LRA Section B.1.1 states that this program will take periodic actions to prevent cables from being exposed to significant moisture by inspecting for water collection in cable manholes and removing water, as needed. The inspection frequency for manholes will be established and performed based on plant-specific operating experience with cable wetting or submergence in manholes. Condition-based inspections of manholes not automatically dewatered by a sump pump will be performed based on (a) the potential for high water table conditions and (b) the occurrence of periods of heavy rain. In addition, operation of dewatering devices, if applicable, will be inspected and operation confirmed before any known or predicted heavy rain or flooding events. The applicant also stated that the periodic inspection will occur at least annually. The manhole inspections will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and verification that dewatering/drainage systems (i.e., sump pumps) and associated alarms, if applicable, operate properly. If water is found during inspection (i.e., cable exposed to significant moisture), corrective actions are taken to keep the cable dry and to assess cable degradation. The first inspection for license renewal is completed before the period of extended operation.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that the activities for preventing and mitigating should be described. These actions should mitigate or prevent aging degradation. The staff noted that inspecting for water collection in cable manholes and removing water will prevent cables from being exposed to wetting or submergence. These actions are necessary to minimize the potential for cable insulation degradation. The staff finds the applicant's "preventive actions" program element to be adequate because specific prevention activities are stated in this new condition monitoring program.

Based on its review of the application, the staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

<u>Parameters Monitored or Inspected</u>. LRA Section B.1.1 states that inspection for water collection in manholes will be performed based on plant-specific operating experience with water accumulation in the manhole, with the inspections to occur at least annually. In-scope transmission cables (115 kV) exposed to significant moisture will be tested to provide an

indication of the condition of the conductor insulation. The specific type of test performed will be determined before the initial test. The test will be proven tests for detecting deterioration of the insulation system because of wetting or submergence, such as dielectric loss (dissipation factor/power factor), AC voltage withstand partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state-of-the-art at the time the test is performed.

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3, which states that this program element should identify the aging effects that the program manages and should provide a link between the parameter or parameters that will be monitored and how the monitoring of these parameters will ensure adequate aging management. For a condition monitoring program, the parameter monitored or inspected should be capable of detecting the presence and extent of aging effects.

The staff noted that long-term wetting of inaccessible transmission cables can cause water-related degradation of cable insulation. The staff noted that performing inspection for water collection in manholes is acceptable to prevent cables from being exposed to significant moisture, defined as periodic exposures to moisture that lasts more than few days (e.g., cable wetting or submergence in water). The staff also noted that the frequency of manhole inspection based on plant-specific operating experience with water accumulation in the manholes, or at least annually, is acceptable because due to the relatively slow rate of propagation for water to permeate the insulation material, the effect of exposure to moisture may take several years to manifest itself.

The staff also noted that inspection for water accumulation in the manholes is taken to prevent cables from being exposed to significant moisture. However, this action is not sufficient to ensure that water is not trapped elsewhere in the raceways. The inspection for water accumulation in manholes is necessary to minimize the potential for insulation degradation. In addition to the inspection, in-scope cables exposed to significant moisture are tested to indicate the condition of the conductor insulation.

The staff finds the applicant's "parameters monitored or inspected" program element to be adequate because the tests proposed by the applicant are acceptable to assess the condition of conductor insulation because those tests are industry standard tests and will ensure the component's intended function during the period of extended operation.

Based on its review of the application, the staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.1.1 states that testing will be performed at least once every 6 years, with the first tests for license renewal occurring before the period of extended operation. For transmission cables exposed to significant moisture, test frequencies may be adjusted based on test results (including trending of degradation where applicable) and operating experience. The applicant also stated that the condition of the cable insulation will be assessed with reasonable confidence using tests such as dielectric loss (dissipation factor/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state-of-the-art at the time the tests are performed. The applicant also stated that the test used to determine the condition of the cable insulation will ensure that the cables continue to meet their intended function during the period of extended operation.

The staff reviewed the applicant's "detection of aging effects" program element against the criteria in SRP-LR Section A.1.2.3.4, which states that the parameters to be monitored or inspected should be appropriate to ensure that the intended function(s) of the SCs will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency and timing of inspection to ensure timely detection of aging effects. In addition, it states that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The staff noted that testing frequency based on the test results and operating experience or at least once every 6 years is acceptable for assessing the condition of cable insulation materials because the proposed test frequency is consistent with GALL Report AMP XI.E3, "Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." Furthermore, SAND 96-0344, Aging Management Guideline for Commercial Nuclear Plants – Electrical Cable and Terminations (September 1996), reiterates that due to the relatively slow rate of propagation for water to ingest into cable material, the effect of exposure to moisture may take several years. The staff finds the applicant's "detection of aging effects" program element to be adequate because the tests proposed by the applicant are acceptable to assess the condition of conductor insulation because those tests are industry standard tests and will ensure the component's intended function during the period of extended operation.

Based on its review of the application, the staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.1.1 states that trending will be used as part of this program based on the ability of trending the test results for the specific test chosen. Since the ability to trend test results will depend on the specific type of test chosen, only results that can be trended will be used to provide additional information on the rate of cable insulation degradation.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus affect timely corrective or mitigative actions. This program element describes how the data collected are evaluated and may also include trending for a forward look. The parameter or indicator trended should be described.

The staff finds the applicant's "monitoring and trending" program element to be adequate because trending based on the ability of trending the test results for the specific test chosen is acceptable. Since the ability to trend test results will depend on the specific type of test chosen, only results that can be trended will be used to provide additional information on the rate of cable insulation degradation. The results will be trended from testing to testing and will provide a basis for timely corrective actions before a loss of intended functions.

Based on its review of the application, the staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.1.1 states that the acceptance criteria for each test will be defined by the type of test performed and the specific cable tested. Acceptance criteria for inspections of manholes are defined by the observation that the cables and support structures are not submerged or immersed in standing water at the time of the inspection.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the SC-intended function(s) are maintained under all CLB design conditions during the period of extended operation.

The staff finds the applicant's "acceptance criteria" program element to be adequate because the applicant described acceptance criteria for inspection of manholes (e.g., observation that cables and support structures are not submerged or immersed in standing water at the time of inspection). The staff also finds that it is acceptable to define the acceptance criteria for each test by the type of test performed and the specific cable tested because the acceptance criteria will be evaluated depending on the specific cable tested, to ensure that high-voltage transmission cable-intended function(s) are maintained during under all CLB design conditions during the period of extended operation.

Based on its review of the application, the staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

Corrective Actions. LRA Section B.1.1 states that an engineering evaluation will be performed when the test acceptance criteria are not met to be sure that the intended functions of the electrical cables can be maintained consistent with the CLB. When an acceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other in-scope transmission cables. Corrective actions may include, but are not limited to, installation of permanent drainage systems, installation of sump pumps and alarms, more frequent cable testing or manhole inspections, or replacement of the affected cable. When an acceptable condition or situation is identified, the requirements of 10 CFR Part 50, Appendix B, will be used to address corrective actions.

The staff reviewed the applicant's "corrective actions" program element against the criteria in SRP-LR Section A.1.2.3.7, which states that the actions to be taken when the acceptance criteria are not met should be described in appropriate detail or referenced to source documents. Corrective actions, including root cause determination and prevention of recurrence, should be timely.

The applicant requires corrective actions when the test acceptance criteria are not met. However, the applicant did not specifically require corrective actions when inspection acceptance criteria are not met to ensure that the intended functions of the electrical cables can be maintained consistent with the CLB. When the inspection acceptance criteria are not met, the applicant is not required to perform an engineering evaluation to ensure that the electrical cables are not submerged again. In a letter dated June 22, 2012, the staff issued RAI B1.1-2, requesting the applicant revise the corrective actions as appropriate to include the corrective actions when inspection acceptance criteria are not met or provide a technical justification of how the proposed corrective actions are consistent with SRP-LR Section A.1.2.3.7, which states that the actions to be taken when the acceptance criteria are not met should be described in appropriate detail or referenced to source documents. In its response dated July 23, 2012, the applicant stated that it will revise the LRA as indicated below (underlined portions) to clarify the corrective actions of the 115 kV Inaccessible Transmission Cable Program:

7. Corrective Actions

<u>Corrective actions are taken and an</u> engineering evaluation will be performed when the test <u>or inspection</u> acceptance criteria are not met to ensure that the intended functions of the electrical cables can be maintained consistent with the current licensing basis. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other in-scope transmission cables. Corrective actions may include, but are not limited to, installation of permanent drainage systems, installation of sump pumps and alarms, more frequent cable testing or manhole inspections, or replacement of the affected cable. When an unacceptable condition or situation is identified, the requirements of 10 CFR Part 50, Appendix B, will be used to address corrective actions.

A.1.1 115 kV Inaccessible Transmission Cable Program

The 115 kV Inaccessible Transmission Cable Program manages the effects of aging on the 115 kV inaccessible transmission cable systems. The program includes periodic actions to prevent inaccessible transmission cables from being exposed to significant moisture. In this program, inaccessible 115 kV transmission cables exposed to significant moisture will be tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies may be adjusted based on test results and operating experience. The specific type of test will be a proven test for detecting deterioration of the cable insulation. The program includes periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, manhole inspection for water after events, such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results. <u>The corrective action program will be entered and an engineering evaluation will be performed when the test or inspection acceptance criteria are not met</u>.

This program will be implemented prior to the period of extended operation. The first cable tests and manhole inspections are to be completed prior to the period of extended operation.

The staff found the applicant's response acceptable because the applicant revised its LRA to specifically require that the CAP will be entered and an engineering evaluation will be performed when the testing or inspection criteria are not met. The staff's concern in RAI B1.1-2 is resolved.

Based on its review of the application and review of the applicant's response to RAI B1.2-1, the staff confirmed that the "corrective actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.7 and, therefore, the staff finds it acceptable.

<u>Operating Experience</u>. LRA Section B.1.1 summarizes operating experience related to the 115 kV Inaccessible Transmission Cables Program. The applicant stated that the 115 kV Inaccessible Transmission Cable Program is a new program. Industry operating experience was considered in the development of this program. Plant operating experience will be gained as the program is implemented and will be factored into the program through the confirmation and corrective action elements of the 10 CFR Part 50, Appendix B, quality assurance program.

The applicant also stated this inspection program applies to a potential aging effect for which there is no operating experience at GGNS indicating the need for an AMP. A search of GGNS operating experience with the 115 kV inaccessible transmission cables and connections in this program identified no age-related failures and no aging mechanisms not considered in SRP-LR. The GGNS program is similar to the program description in the GALL Report AMP XI.E3, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects described herein. As such, operating experience assures that implementation of the 115 kV Inaccessible Transmission Cable Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the CLB for the period of extended operation.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that for new AMPs that have yet to be implemented at an applicant's facility, the programs have not yet generated any operating experience. However, there may be other relevant plant-specific operating experience at the plant or generic operating experience in the industry that is relevant to the AMP's program elements, even though the operating experience was not identified as a result of the implementation of the new program. Thus, for a new program, an applicant may need to consider the impact of relevant operating experience that results from the past implementation of its existing AMPs that are existing programs and the impact of relevant generic operating experience on developing the program elements. Therefore, operating experience applicable to a new program should be discussed.

The applicant stated that a search of GGNS operating experience with the 115 kV inaccessible transmission cables and connections in this program identified no age-related failures, and no aging mechanisms not considered in the GALL Report have been identified. During the switchyard walkdown, the staff noted that Manhole 15 (MH-15) contains the 115 kV in-service transmission cables and the 115 kV transmission spare cables. These cables have the same manhole, but different vaults. The spare cables have a manhole cover and appeared to have the new sump pump installed. However, the vault containing in-service cables appears to have never been inspected for water and does not have a sump pump. This vault is covered by a thick concrete slab with no manhole cover. When a power cable is exposed to wet, submerged, or other adverse environmental conditions for which it was not designed, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. This can potentially lead to failure of the cable's insulation system. In a letter dated June 22, 2012, the staff issued RAI B1.1-1, requesting the applicant confirm that MH-15 containing in-service cables has been inspected. The staff also requested the applicant to describe recent operating experience with water accumulation in MH-15. If water is found submerging cables, the staff requested the applicant to describe corrective actions to prevent future cable submergence conditions. In response to the staff's request, in a letter dated July 23, 2012, the applicant stated that it inspected the 115 kV cables and the associated manhole MH-15 in 2009 and 2010. In 2009, a condition report was written for MH-15 stating that this cable manhole contained water, but there was no indication that the water level in the manhole was above the cables. In 2010, a condition report was written for MH-15 stating that water was discovered during the manhole inspection, but the water was not covering the cables. The applicant further stated that Entergy has a design modification prepared to install a solar-powered sump pump in manhole MH-15. The purpose of this modification is to provide a method to remove water from the MH-15 vault that contains in-service cables. The staff found the applicant response acceptable because the applicant has inspected 115 kV service cables and found that there was water in MH-15, but no submerged cables were found. The applicant plans to install a sump pump to remove water from the MH-15 vault that contains in-service cables. The staff concern in RAI B1.1-1 is resolved.

Based on its review of the application and review of the applicant's response to RAIs B1.1-1 and B1.1-2, 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 will 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 appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.1.1 provides the UFSAR supplement for the 115 kV Inaccessible Transmission Cable Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description for this type of program as described in SRP-LR Table 3.0.1.

The staff also noted that the applicant committed (Commitment No. 1) to implement the new 115 kV Transmission Cable 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 technical review of the applicant's 115 kV Transmission Cable Program, 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 Periodic Surveillance and Preventive Maintenance

Summary of Technical Information in the Application. LRA Section B.1.35, as modified by letters dated December 20, 2013, May 13, 2014, and November 6, 2014, describes the existing Periodic Surveillance and Preventive Maintenance Program as plant specific, with an enhancement. The LRA states that the AMP manages aging effects not managed by other AMPs, including loss of material, loss of coating integrity, cracking, and change in material properties. The LRA also states that the AMP addresses piping and piping components in the LPCS system, HPCS system, RHR system, pressure relief system, RCIC system, nonsafety-related systems affecting safety-related systems (CRD system, circulating water (CW) system, and floor and equipment drain system), and the floor and equipment drain system. The AMP also addresses recurring internal corrosion issues in the CW, SSW, plant service water, and fire protection systems. The LRA further states that the AMP addresses the rubber gasket/seal for upper containment pool gates in the containment system. The staff notes that the applicant addressed those portions of LR-ISG-2012-02 pertaining to recurring internal corrosion and loss of coating integrity by modifying this program. The staff's evaluation of the program changes to address recurring internal corrosion is documented in SER Section 3.3.2.2.7. Additionally, the staff's evaluation of the program changes to address loss of coating integrity is documented in SER Section 3.0.3.3.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these program elements follows. The staff's review of the "corrective actions," "confirmation process" and "administrative controls" programs elements are documented in SER Section 3.0.4.

Scope of Program. LRA Section B.1.35, as modified in response to RAI B.1.41-3c, by letter dated December 20, 2013, states that the program includes piping and piping components in the LPCS system, HPCS system, RHR system, pressure relief system, RCIC system, nonsafety-related systems affecting safety-related systems (CRD system, CW system, moisture separator-reheater system, and floor and equipment drain system), and the floor and equipment drain system. Section B.1.35 also states that the AMP addresses the rubber gasket/seal for upper containment pool gates in the containment system.

The staff reviewed the applicant's "scope of program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that this element includes the specific SCs managed by the program.

The staff noted that, in the portion of its letter dated May 13, 2014, relating to recurring internal corrosion, the applicant stated that this program monitors for loss of material due to microbiologically-influenced corrosion in the CW, SSW, plant service water, and fire protection systems. However, the corresponding change made to the table in the Periodic Surveillance and Preventive Maintenance Program also included the component cooling water system. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-RIC-1, part 1, requesting that the applicant clarify this apparent discrepancy. By letter dated November 6, 2014, the applicant stated that microbiologically-influenced corrosion has not occurred in the component cooling water system, and amended the table for the Periodic Surveillance and Preventive Maintenance Program and the corresponding UFSAR supplement by removing the component cooling water system from the systems listed. The staff finds the applicant's response acceptable because microbiologically-influenced corrosion is not a recurring internal corrosion mechanism that is applicable to the component cooling water system. The staff's concern described in RAI 3.0.3 1-RIC-1, part 1 is resolved.

Based on its review of the application, the staff confirmed that the "scope of program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.1.35 states that the program is a condition monitoring program and does not include preventive actions.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that if the program does not rely on preventive actions, the information need not be provided.

The staff noted that the Periodic Surveillance and Preventive Maintenance Program does not prevent loss of material, cracking, or change in material properties, but instead provides a means for detecting the degradation before a loss of intended function.

The staff finds the applicant's "preventive actions" program element to be adequate because the applicant has provided information that clearly identifies the program as being a conditioning monitoring program only, with no preventive actions needing description.

Based on its review of the application, the staff confirmed that the “preventive actions” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.1.35 states that the program monitors and inspects parameters linked to the degradation of the particular structure or component intended function(s).

The staff reviewed the applicant’s “parameters monitored or inspected” program element against the criteria in SRP-LR Section A.1.2.3.3, which states that the program element should identify the aging effects that the program manages and should provide a link to the parameters that will be monitored. SRP-LR Section A.1.2.3.3 also states that the parameters monitored should be capable of detecting the presence and extent of aging effects.

The staff did not find the applicant’s “parameters monitored or inspected” program element to be adequate because the application did not have sufficient detail for the staff to conclude that the parameters monitored are appropriate or are capable of detecting the presence and extent of aging effects. By letter dated April 11, 2012, the staff issued RAI B.1.35-1 requesting that the applicant revise Section B.1.35 to include the specific parameters monitored and their related aging effects for the SC groupings managed by the program.

In its response dated May 9, 2012, the applicant revised the “parameters monitored or inspected” program element of LRA Section B.1.35 to state that the program monitors cracking and change in material properties for elastomer components and the surface condition of the internal and external surfaces of the remaining (metallic) components to manage loss of material.

The staff finds the applicant’s response to be acceptable and the “parameters monitored or inspected” program element to be adequate because monitoring for the presence of cracking and change in material properties is capable of detecting elastomer degradation, consistent with the GALL Report guidance that identifies hardening and loss of strength as the applicable elastomer aging effects in air environments (e.g., GALL Report item VII.F2.AP-102). Also, monitoring the surface condition is capable of detecting loss of material of metallic components, which is the identified aging effect in the GALL Report for steel and stainless steel piping components exposed to water environments (e.g., GALL Report item V.D2.EP-60). The staff noted that this program is used to manage loss of material of gray cast iron valve bodies, which are subject to selective leaching and would thus require physical manipulation to detect loss of material due to this aging mechanism. However, the applicant is using the Selective Leaching Program to manage loss of material due to selective leaching for gray cast iron. The staff’s concern described in RAI B.1.35-1 is resolved.

The staff noted that, by letter dated May 13, 2014, the applicant amended the “parameters monitored or inspected” program element to state that the program will monitor the wall thickness to manage loss of material due to recurring internal corrosion, and it will monitor the condition of internal coated surfaces of components to manage loss of coating integrity. The staff finds these amendments of the AMP to be acceptable because the program element appropriately reflects the additional monitored parameters. The staff’s evaluations of the applicant’s activities to address recurring internal corrosion and loss of coating integrity are documented in SER Sections 3.3.2.2.7 and 3.0.3.3 respectively.

Based on its review of the application, the staff confirmed that the “parameters monitored or inspected” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.1.35 states that preventive maintenance activities and periodic surveillances provide for periodic component inspections to detect aging effects. The LRA also states that established techniques such as visual inspections are used, and each inspection occurs at least once every 5 years. The LRA further states that, for each activity that refers to a representative sample, a representative sample is 20 percent of the population with a maximum of 25 components.

The staff reviewed the applicant’s “detection of aging effects” program element against the criteria in SRP-LR Section A.1.2.3.4, which states that the program element should address how age-related degradation will be detected prior to a loss of component function and should describe all aspects of data collection activities (e.g., inspection technique, frequency, and timing). The SRP-LR Section A.1.2.3.4 also states that inspection samples should be biased toward locations most susceptible to the specific aging effect of concern.

The staff did not initially find the applicant’s “detection of aging effects” program element to be adequate because (1) LRA Section B.1.35 did not specify that inspection samples should be biased toward locations most susceptible to aging and (2) the staff did not consider the LRA to have the necessary detail regarding how data are collected. By letter dated April 11, 2012, the staff issued RAI B.1.35-2, requesting that the applicant revise the “detection of aging effects” program element of LRA Section B.1.35 to include the selection of inspection locations most susceptible to aging. The staff also issued RAI B.1.35-3, requesting that the applicant revise the “detection of aging effects” program element to include specific inspection techniques that will be used to detect the aging effects. In this RAI, staff also requested that the applicant revise the LRA to state the qualification requirements of personnel who will be performing the inspections, or justify their exclusion.

In its response dated May 9, 2012, the applicant revised the “detection of aging effects” program element of LRA Section B.1.35 to state that the selection of components to be inspected will focus on locations that are most susceptible to aging, where practical. The applicant also revised the LRA to state that visual inspections and manual flexing will be used to detect the aging of elastomers and visual or NDE techniques will be used to detect the aging of the metallic components. The applicant further revised the LRA to state that inspections will be performed by qualified personnel.

The staff finds the applicant’s response acceptable and the “detection of aging effects” program element to be adequate because visual inspections and manual flexing are capable of detecting cracking and change in material properties of elastomers. Also, visual inspections and NDE techniques are capable of detecting loss of material of metallic components. Further, the performance of these elastomer and metallic component inspections by qualified personnel at least once every 5 years on a representative sample of components, focusing on locations most prone to aging, is capable of detecting aging before loss of component function. The staff’s concerns described in RAI B.1.35-2 and RAI B.1.35-3 are resolved.

Based on its review of the application and review of the applicant’s responses to RAI B.1.35-2 and RAI B.1.35-3, the staff confirmed that the “detection of aging effects” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.1.35 states that preventive maintenance activities provide for monitoring and trending of aging degradation. The LRA also states that inspection intervals are established such that they provide for timely detection of component degradation. The LRA further states that inspection intervals take into consideration industry and plant-specific operating experience and manufacturers' recommendations.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described and the results should be evaluated against the acceptance criteria to effect timely corrective or mitigative actions.

The staff finds the applicant's "monitoring and trending" program element to be adequate because the program's preventive maintenance activities include inspection intervals that are informed by operating experience, such that aging degradation can be detected prior to loss of intended function.

Based on its review of the application, the staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.1.35 states that acceptance criteria are defined in specific inspection procedures, which confirm that the structure or component intended function(s) are maintained by verifying the absence of aging effects or by comparing applicable parameters to limits established by the plant design basis.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described and the acceptance criteria should ensure that the component's intended function(s) are maintained consistent with the CLB.

The staff did not find the applicant's "acceptance criteria" program element to be adequate because the application did not have sufficient detail on the inspection procedures for the staff to conclude that the acceptance criteria will be capable of confirming that component intended functions will be maintained. By letter dated April 11, 2012, the staff issued RAI B.1.35-4, requesting that the applicant revise the "acceptance criteria" program element of LRA Section B.1.35 to include specific acceptance criteria (e.g., any indication of relevant degradation, pipe wall remaining above minimum design wall thickness, absence of cracking) for each of the SC groupings managed by the program.

In its response dated May 9, 2012, the applicant revised the "acceptance criteria" program element of LRA Section B.1.35 to state that the acceptance criteria for elastomers includes no significant change in material properties or cracking while visually observing and flexing components. The applicant also stated that the acceptance criteria for metallic components include no unacceptable loss of material, such that component wall thickness remains above the required minimum.

The staff finds the applicant's response to be acceptable and the "acceptance criteria" program element to be adequate because maintaining no significant change in material properties or cracking of elastomers and maintaining metallic component wall thicknesses above required minimums ensure that component intended functions will be maintained consistent with the CLB. The staff's concern described in RAI B.1.35-4 is resolved.

Based on its review of the application and review of the applicant's response to RAI B.1.35-4, the staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," 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 1. LRA Section B.1.35 states an enhancement to the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the applicant stated that the program will be enhanced to revise program guidance documents as necessary to include all inspection activities provided in the program description of LRA Section B.1.35, which is summarized in the staff's evaluation of the "scope of program" program element above. The staff reviewed this enhancement and finds it acceptable, because this enhancement to the program, as revised by the responses to RAIs B.1.35-1, B.1.35-2, B.1.35-3, B.1.35-4, and B.1.41-3c, establishes appropriate inspection activities capable of ensuring that degradation will be detected before the loss of intended function.

By letter dated November 6, 2014, the applicant amended the enhancement to the program given in LRA Sections A.1.35, A.4 (Commitment No. 25), and B.1.35 to be more consistently worded for the three sections. The amended enhancement added the "monitoring and trending" and "corrective actions" program elements to the list of affected elements. In addition, the enhancement clarified that the enhanced activities included, not just the activities described in the table provided in the program description for LRA Section B.1.35, but all the activities described in LRA Section B.1.35. The staff finds the amended enhancement acceptable because it captures all of the recent changes made to the program to ensure that degradation will be detected before the loss of intended function.

Based on reviews of LRAs and industry operating experience conducted by the staff, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letter dated January 2, 2014, the staff issued RAI 3.0.3-2 requesting that the applicant address several questions associated with managing loss of coating integrity. As a result of this RAI and follow-on RAIs, the applicant made several changes to the Periodic Surveillance and Preventive Maintenance Program in order to manage loss of coating integrity. The staff's evaluation of the changes described in these enhancements is documented in SER Section 3.0.3.3.

Operating Experience. LRA Section B.1.35 summarizes operating experience related to the Periodic Surveillance and Preventive Maintenance Program. The applicant stated that operating experience includes NDE wall-thickness measurements performed on diesel generator exhaust piping in 2005, which showed acceptable results and confirmed that there was no indication of aging. The applicant also stated that, in 2006, a visual inspection of the internal surfaces of a check valve in the component cooling water system found significant wear. The applicant stated that, after the valve was replaced, there was no other indication of aging such as erosion or corrosion. The applicant cited these examples of operating experience as evidence that the program is effective for managing aging effects for components.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that operating experience should be discussed. SRP-LR

Section A.1.2.3.10 also states that this information 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. 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 review of the application, the staff finds that (1) the applicant has appropriately evaluated plant-specific and industry operating experience, (2) operating experience related to the applicant's program demonstrates that it will adequately manage the effects of aging on SSCs within the scope of the program, and (3) implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criteria in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.1.35 provides the UFSAR supplement for the Periodic Surveillance and Preventive Maintenance Program. The UFSAR supplement includes Commitment No. 25 in LRA Table A.4, in which the applicant committed to updating the program guidance documents as necessary to include all inspection activities provided in the program description of LRA Section B.1.35, which the staff evaluated in the "scope of program" program element and enhancement in this AMP. 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 LRA Section A.1.35 does not include the minimum 5-year inspection frequency. 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 incorporate this information into its UFSAR supplement. By letter dated April 11, 2012, the staff issued RAI B.1.35-5 requesting that the applicant revise LRA Section A.1.35 to include the frequency of inspections to be conducted during the period of extended operation.

In its response dated May 9, 2012, the applicant revised the UFSAR supplement in LRA Section A.1.35 to state that inspections will be conducted at least once every 5 years during the period of extended operation. The applicant also revised the UFSAR supplement to describe the inspections in greater detail, including the specific components and systems inspected.

The staff finds the applicant's response acceptable because the applicant included the 5-year inspection frequency in the UFSAR supplement, which provides an important detail on the basis for how this program will manage aging during the period of extended operation. Therefore, the UFSAR supplement for the Periodic Surveillance and Preventive Maintenance Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.1.35-5 is resolved.

By letters dated May 13, 2014, and September 11, 2014, the applicant amended the UFSAR supplement description in LRA Section A.1.35, to add "recurring internal corrosion" and "loss of coating integrity" as additional, applicable aging effects that will be managed by the program. The applicant also clarified that the frequencies of inspections for coating integrity and recurring internal corrosion due to microbiologically-influenced corrosion are based on inspection results instead of at least once every 5 years. In addition, the applicant added extensive details related to the coating integrity inspections and the microbiologically-influenced corrosion inspections.

The staff finds that the information in the UFSAR supplement, as amended, is an adequate summary description of the program. In addition, the staff's evaluation of the UFSAR changes to address loss of coating integrity is documented in SER Section 3.0.3.3.

Conclusion. On the basis of its technical review of the applicant's Periodic Surveillance and Preventive Maintenance Program, 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). Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 25 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

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

3.0.3.3.1 Technical Information in the Application

Based on reviews of LRAs and industry operating experience conducted by the staff, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letter dated January 2, 2014, the staff issued RAI 3.0.3-2 requesting that the applicant address several questions associated with managing loss of coating integrity. In its response dated May 13, 2014, the applicant revised the Periodic Surveillance and Preventive Maintenance, Fire Water System, and Service Water Integrity Programs to address loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letter dated September 11, 2014, the staff issued follow-up requests for additional information. The applicant responded on November 6, 2014. On November 14, 2014, the staff issued LR-ISG-2013-01, which contains the current staff-recommended actions to manage loss of coating integrity. The staff's evaluation of this issue and the applicant's responses are presented here.

3.0.3.3.2 Staff Evaluation

By letter dated January 2, 2014, the staff issued RAI 3.0.3-2 requesting that, if coatings have been installed on the internal surfaces of in-scope components (i.e., piping, piping components, heat exchangers, and tanks), the applicant state the inspection method, when inspections will commence and the frequency of subsequent inspections, the extent of inspections, the training and qualification of individuals involved in coating inspections, how trending of coating degradation will be conducted, acceptance criteria, and corrective actions for coatings that do not meet acceptance criteria.

The staff noted that the applicant included 10 enhancements to the Service Water Integrity Program and enhanced the Periodic Surveillance and Preventive Maintenance Program in order to incorporate the inspections, testing, and actions below to address loss of coating integrity. The staff's evaluation of enhancements to the Fire Water System to address loss of coating integrity is documented in SER Section 3.0.3.1.20.

In its response dated May 13, 2014, the applicant provided the following:

Visual Inspections. The applicant stated that visual inspections will be conducted on the internal surfaces of coated components.

The staff finds this portion of the RAI response acceptable because it is consistent with LR-ISG-2013-01 and visual inspections are an effective means to detect coating degradation.

Baseline and Subsequent Frequency of Inspections. The applicant stated that baseline inspections will begin during the 10-year period prior to the period of extended operation and be completed no later than the last scheduled refueling outage prior to the period of extended operation. Subsequent inspections will be based on the initial inspection results as follows: (a) if no peeling, delamination, blisters, or rusting are detected and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years, (b) if no indications are found during the inspection of one train, the redundant train will not be inspected and the subsequent inspection will be on the redundant train, and (c) if the inspection results do not meet the above (however, a coating specialist has determined that no remediation is required), subsequent inspections will be conducted on an every other refueling outage interval. The applicant also stated that, "[i]nspections of coatings that are repaired, replaced or newly installed are not periodic activities performed to manage the effects of aging. Such inspections confirm adequacy of application of protective coatings which is not an activity necessary to manage the effects of aging in accordance with the license renewal rule."

The staff noted that, if no indications are found during the inspection of one train, the redundant train would not need to be inspected as long as: (a) an identical coating/lining material was installed with the same installation requirements in the redundant train (e.g., piping segments, tanks) with the same operating conditions, and (b) the components within the redundant trains are not subject to turbulent conditions. By letter dated September 11, 2014, the staff issued RAI 3.0.3-2a Request (1) requesting that the applicant state the basis for why inspection results on one train are sufficiently representative of the coating condition in a redundant train.

In its response dated November 6, 2014, the applicant enhanced the Periodic Surveillance and Preventive Maintenance Program and Service Water Integrity Program to state that, when the inspections of coatings on one train do not detect any indications, the redundant train's coatings will not have to be inspected in that inspection interval as long as the coatings in the redundant train have the same coating and the redundant train does not have turbulent flow. The applicant stated that, "[u]nder these conditions, inspection results on one train are representative of the coating condition on redundant train(s) such that it is acceptable to extend the inspection interval for redundant train(s) when no indications are found during the inspection of the initial train."

The staff finds the applicant's response and proposal for beginning inspections and the frequency of subsequent inspections acceptable because they are consistent with LR-ISG-2013-01 and: (a) baseline inspections will be conducted prior to entering the period of extended operation in order to provide insight into the condition of coatings after many years of service, (b) subsequent inspection intervals will be based on the results of prior inspections such that, where degraded coatings are noted, more frequent inspections will occur, (c) the maximum inspection intervals are consistent with the staff's recommended actions to manage loss of coating integrity, and (d) conducting alternating inspections of redundant trains with the same coatings when no indications are detected in prior inspections and turbulent flow conditions do not exist is consistent with the staff's recommended actions to manage loss of coating integrity. The staff's concern described in RAI 3.0.3-2a Request (1) is resolved.

The applicant revised its Periodic Surveillance and Preventive Maintenance Program and Service Water Integrity Program to conduct one or more inspections or tests whenever coating conditions such as cracking, peeling, blistering, delamination, rust, or flaking are identified during inspections. The tests include lightly tapping the coating to detect degraded conditions, wet-sponge testing, adhesion testing, and ultrasonic examinations. The staff finds this change acceptable because they are effective means to determine the degree of degradation in coatings.

Extent of Inspections. The applicant stated that all accessible internal surfaces of tanks and heat exchangers are inspected; and a representative sample of the internal surfaces of piping is inspected, consisting of 73 1-foot axial length circumferential segments of piping or 50 percent of the pipe length for each coating material and environment combination.

The staff finds the applicant's response and proposal acceptable because it is consistent with LR-ISG-2013-01, which ensures that a minimum number of inspections are conducted.

Training and Qualification of Personnel. The applicant stated that coating inspections will be performed by individuals qualified to ANSI N45.2.6, "Qualification of Inspections, Examinations, and Testing Personnel for Nuclear Power Plants." The applicant also stated that the evaluation of inspection findings will be conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D7108-5, "Standard Guide for Establishing Qualifications for a Nuclear Coating Specialist."

The staff noted that qualifications meeting the recommendations in RG 1.54 are consistent with the staff's recommended actions to manage loss of coating integrity. The staff finds the training and qualification requirements acceptable because ANSI N45.2.6 certification is an acceptable basis for qualifying coatings inspectors based on RG 1.54, June 1973, Section C.1, which endorses conformance to the ANSI N45.2 quality assurance standards, and because the use of D7108-05 is endorsed by RG 1.54.

Monitoring and Trending of Results. The applicant stated that monitoring and trending is accomplished by preventive maintenance activities. In a letter dated November 6, 2014, the applicant revised LRA Sections B.1.35 and B.1.41, Periodic Surveillance and Preventive Maintenance and Service Water Integrity Programs, respectively, to state that: (a) "[a]n individual knowledgeable and experienced in nuclear coatings work will prepare a coating report; and (b) the coating inspection report will include a list of locations identified with coating degradation, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations."

The staff noted that LRA Section B.1.35 was revised to state that the results of previous inspections are reviewed prior to conducting a coating inspection; however, LRA Section B.1.41 does not include this requirement. The staff also noted that LRA Section B.1.21, Fire Water System Program, does not include any of the above-described requirements. In addition, the staff has concluded that a coatings specialist should prepare the coating report and the term "an individual knowledgeable and experienced in nuclear coatings work" lacks sufficient specificity for the staff to conclude that the individual will be appropriately qualified to perform the task. By letter dated September 11, 2014, the staff issued RAI 3.0.3-2a Request (2), requesting that the applicant state: (a) the specific qualifications for the individual that prepares the coating report for the Periodic Surveillance and Preventive Maintenance, Fire Water System, and Service Water Integrity Programs, (b) how the results of coatings inspections will be monitored and trended for the Service Water Integrity Program, and (c) how the results of coatings inspections will be monitored, trended, and reported for the Fire Water System Program.

In its response dated November 6, 2014, the applicant revised LRA Sections A.1.21, A.1.35, A.1.41, A.4, B.1.21, B.1.35, and B.1.41, as necessary, to state: (a) post-inspection reports will be prepared by a nuclear coating specialist, (b) results of previous inspections will be reviewed prior to conducting a coating inspection, and (c) the qualifications of individuals conducting coating inspections. In addition, the Fire Water System Program and the UFSAR supplement description of the program were revised to include both the level of detail to be included in coating inspection reports, similar to that contained in the Periodic Surveillance and Preventive Maintenance and Service Water Integrity Programs, and the qualifications for personnel conducting coating inspection activities.

The staff finds the applicant's response and proposal to monitor and trend coating degradation acceptable because they are consistent with LR-ISG-2013-01, which ensures that individuals that prepare inspection reports are appropriately qualified and the results of prior inspections are used to inform the inspectors of potential coating degradation prior to conducting subsequent inspections. The staff's concerns described in RAI 3.0.3-2a Request (2) are resolved.

Acceptance Criteria. The applicant stated that peeling and delamination are not acceptable; cracking is not acceptable if there is also evidence of delamination or loss of adhesion. By letters dated August 19, 2015, and November 23, 2015, the applicant stated that blisters are limited to a few small intact blisters completely surrounded by sound coating bonded to the surface. When peeling, delamination, cracking, or loss of adhesion is detected, follow-up evaluations such as an adhesion test will be performed. If base metal is exposed and accompanied by corrosion, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its CLB intended function until the next inspection.

The staff noted that the applicant stated that a volumetric examination will be performed if there is evidence of "accelerated corrosion;" however, the staff has concluded that, if coatings are credited for corrosion prevention (e.g., corrosion allowance in design calculations is zero, the "preventive actions" program element credited the coating) and the base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the degraded coating is examined to determine if the minimum wall thickness is met and will be met until the next inspection. The staff also noted that the Fire Water System Program does not include acceptance criteria for loss of coating integrity. By letter dated September 11, 2014, the staff issued RAI 3.0.3-2a Request (3), requesting that the applicant state: (a) the basis for why conducting volumetric wall thickness examinations of components only when the extent of loss of material is characterized as "accelerated corrosion" is sufficient to provide reasonable assurance that the CLB intended function(s) of components with exposed base metal or base metal in the vicinity of a blister will be met, and (b) the acceptance criteria that will be used to assess degraded coatings in the fire water system.

In its response dated November 6, 2014, the applicant stated that the term "accelerated corrosion" was revised to "corrosion;" and the Fire Water System Program was revised to state the same acceptance criteria as for the Periodic Surveillance and Preventive Maintenance and Service Water Integrity Programs.

The staff finds the applicant's response and proposed acceptance criteria acceptable because they are consistent with LR-ISG-2013-01, which states that peeling and delamination are not acceptable, cracking can be evaluated by a coatings specialist, and a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate meet acceptance criteria. The staff's concern described in RAI 3.0.3-2a Request (3) is resolved.

Corrective Actions for Coatings That Do Not Meet Acceptance Criteria. The applicant stated that "[c]orrective actions for unacceptable inspection findings will be determined in accordance with the GGNS 10 CFR Part 50 Appendix B Corrective Action Program (CAP)."

The staff has concluded that coatings that do not meet acceptance criteria should be repaired, replaced, or removed, and testing or examination should be conducted to ensure that the extent of repaired, replaced, or removed coatings encompasses sound coating material. Although the applicant's acceptance criteria state the aging mechanisms that are not acceptable, the "corrective actions" program element does not state that the coatings will be repaired, replaced, or removed, and that testing or examination will be conducted to ensure that the extent of repaired, replaced, or removed coatings encompasses sound coating material. The "corrective actions" program element lacks sufficient specificity for the staff to complete its evaluation. By letter dated September 11, 2014, the staff issued RAI 3.0.3-2a Request (4), requesting that the applicant state the specific corrective actions that will be taken when loss of coating integrity is detected that does not meet acceptance criteria.

In its response dated November 6, 2014, and as amended by letter dated August 19, 2015, the applicant stated that: (a) if peeling, delamination, cracking, or loss of adhesion is identified, the degraded condition will be evaluated by techniques such as adhesion testing, (b) "[c]oatings that do not meet acceptance criteria will be repaired or replaced," and (c) in the event that base metal is exposed, "[i]f repair or replacement of the coating is postponed, the evaluation will consider the minimum wall thickness requirements and the rate of corrosion and confirm the component remains acceptable for continued service until the next inspection or repair opportunity." In addition, the applicant revised the Fire Water System Program to state that dry film thickness readings, spot wet sponge tests, and ultrasonic thickness readings will be conducted where pitting or corrosion is detected in the fire water storage tank walls or floor.

The staff finds the applicant's response and proposed "corrective actions" program elements acceptable, in part, because repairing or replacing coatings that do not meet acceptance criteria is consistent with LR-ISG-2013-01. However, the applicant did not state: (a) what alternatives to adhesion testing would be conducted in order to evaluate degraded coatings, (b) how downstream flow blockage will be addressed when degraded coatings that do not meet acceptance criteria are returned to service, and (c) what actions would be taken if degraded coatings exhibiting peeling or delamination are returned to service without correction. In addition, in regard to fire water storage tanks, NFPA 25, Section 9.2.7 states that adhesion testing should be conducted in addition to those tests that the applicant stated it will conduct when coating defects are detected. The staff addressed the fire water storage tank adhesion testing question in RAI 3.0.3.1-FWS-2a, as documented in SER Section 3.0.3.1.20. The staff required additional information to resolve the above concerns in RAI 3.0.3-2a Request (4).

By letter dated April 6, 2015, the staff issued RAI 3.0.3-2b requesting that the applicant state (a) what alternatives to adhesion testing will be conducted in order to evaluate degraded coatings, (b) how potential downstream flow blockage due to degraded coatings that do not meet acceptance criteria will be evaluated prior to returning a degraded coating to service, and (c) what actions would be taken if degraded coatings exhibiting peeling or delamination are returned to service without correction.

The applicant originally responded to this RAI on May 20, 2015; however, it revised its response as stated in an August 19, 2015, letter. The applicant revised LRA Section B.1.41 to state that if a coatings specialist determines that coating remediation is required, the coated component can be returned to service if the following actions, testing, and examination occur: (a) removal of blisters in excess of a few small intact blisters or blisters not completely surrounded by coating bonded to the substrate, (b) removal of delaminated or peeled coatings, (c) adhesion testing is conducted in three locations in accordance with standards cited in RG 1.54, (d) feathering of the outermost coating and adhesion testing of the surface surrounding the feathering, (e) ultrasonic testing to ensure minimum wall thickness requirements are met, (f) an evaluation to ensure that downstream flow blockage is not an issue, and (g) follow-up inspections within 2 years and every 2 years until the coating is repaired, replaced, or removed.

The staff noted that the applicant had not included the changes to its Periodic Surveillance and Preventive Maintenance Program in the August 19, 2015, letter. By letter dated October 29, 2015, the staff issued RAI 3.0.3-3 requesting that the applicant provide the changes to its Periodic Surveillance and Preventive Maintenance Program. In its response dated November 23, 2015, the applicant provided the changes to the Periodic Surveillance and Preventive Maintenance Program. The staff finds the applicant's response acceptable because the changes to the Periodic Surveillance and Preventive Maintenance Program are consistent with the changes described in this section in this SER. The staff's concern described in RAI 3.0.3-3 is resolved.

The staff finds the applicant's response acceptable because the applicant's proposal in relation to alternative adhesion testing methods and to potential downstream flow blockage due to degraded coatings, and the actions, testing, and examinations that will be conducted prior to returning a component to service with degraded coatings are consistent with the "acceptance criteria" and "corrective actions" program elements of AMP XI.M42. The staff's concerns described in RAI 3.0.3-2a Request (4) and RAI 3.0.3-2b are resolved.

The staff noted that LRA Section B.1.35 lists the program elements that are required to be enhanced for the Periodic Surveillance and Preventive Maintenance Program. The staff also noted that the "monitoring and trending" program element includes new requirements necessary to effectively manage loss of coating integrity; however, this program element is not included in the list of elements affected. In addition, the changes to the program submitted in response to RAI 3.0.3-2a resulted in changes to the "corrective actions" program element. In response to RAI 3.0.3-2a Request (5) the applicant included the "monitoring and trending" and "corrective actions" program elements in the list of program elements requiring enhancement. The staff finds this change acceptable because the program now accurately reflects all program elements that must change. The staff's concern described in RAI 3.0.3-2a Request (5) is resolved.

3.0.3.3.3 UFSAR Supplement

The staff noted that, in its response dated August 19, 2015, the applicant revised LRA Sections A.1.21, A.1.35, and A.1.41, to address loss of coating integrity for the Fire Water System, Periodic Surveillance and Preventive Maintenance, and Service Water Integrity Programs, respectively. In addition, the applicant revised the UFSAR supplement for the Periodic Surveillance and Preventive Maintenance Program in its response dated November 23, 2015. The staff's evaluation of changes to the UFSAR supplement for the Fire Water System Program is documented in SER Section 3.0.3.1.20.

LR-ISG-2013-01, Table 3.0-1, AMP XI.M42 states that the UFSAR supplement for programs that will manage loss of coating integrity should state key aspects of the program associated with coating degradation, including periodic visual inspections to detect potential loss of coating integrity; follow-up testing that will be conducted when degradation does not meet acceptance criteria; and the basis for the training and qualification of individuals involved in coating inspections. The staff noted that LRA Sections A.1.35 and A.1.41 address these aspects of managing loss of coating integrity. The staff also noted that the applicant committed (Commitment No. 35) to enhance the program by revising Service Water Integrity Program documents to include inspections for loss of material due to erosion.

The staff finds that the information in the UFSAR supplements, as amended by letter dated August 19, 2015, and November 23, 2015, are adequate summary descriptions of the associated programs.

3.0.3.3.4 Conclusion

On the basis of its technical review of the applicant's changes to the Fire Water System, Periodic Surveillance and Preventive Maintenance and Service Water Integrity Programs to address loss of coating integrity, 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 these AMPs and concludes that they provide 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

Pursuant to 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:

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

(8) Confirmation Process – The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions are completed and effective.

(9) 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 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, 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, “Aging Management Programs,” and LRA Appendix B, “Aging Management Programs and Activities,” Section B.0.3, “Corrective Actions, Confirmation Process 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 and nonsafety-related components.

LRA Appendix A, Section A.1 states:

> GGNS QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The GGNS Quality Assurance Program applies to safety-related structures and components. The appendix also states that corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished in accordance with the established GGNS corrective action and document control programs and are applicable to all aging management programs.

LRA Appendix B, Section B.0.3 states:

> **Corrective Actions:**
>
> The corrective action controls of the GGNS (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation.
>
> **Confirmation Process:**
>
> Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished in accordance with the established GGNS Corrective Action Program (CAP) and Document Control Program. The confirmation process is part of the CAP and includes the following:
>
> - Reviews to assure that corrective actions are adequate
> - Tracking and reporting of open corrective actions
> - Review of corrective action effectiveness
>
> Any follow-up inspection required by the confirmation process is documented in accordance with the CAP. The CAP constitutes the confirmation process for aging management programs and activities.

Administrative Controls:

Administrative (document) control for both safety-related and nonsafety-related structures and components is accomplished per the existing document control program. The GGNS administrative controls are consistent with NUREG-1801.

3.0.4.2 Staff Evaluation

The staff reviewed LRA Sections Appendix A, Section A.1 and Appendix B, and LRA Section B.0.3, which describe how the existing GGNS quality assurance program includes the QA-related elements (corrective action, confirmation process, and administrative controls) for AMPs consistent with the staff's guidance described in BTP 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, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in LRA Sections Appendix A, Section A.1, and Appendix B, Section B.0.3, were determined to be consistent with the staff's position regarding QA for aging management. The staff concludes that the QA attributes (corrective action, confirmation process, and administrative control) of the applicant's AMPs are consistent with 10 CFR 54.21(a)(3).

3.0.5 Operating Experience for Aging Management Programs

3.0.5.1 Summary of Technical Information in Application

LRA Section B.0.4 describes how the applicant considered operating experience in the preparation of the application. The LRA states that the applicant reviewed operating experience for the programs and activities credited with managing the effects of aging, and this review included corrective actions resulting in program enhancements. For inspection programs, the LRA states that reports of recent inspections, examinations, or tests were reviewed to determine if aging effects had been identified for applicable components. For monitoring programs, the LRA states that reports of sample results were reviewed to determine if parameters were being maintained as required by the program. The LRA also states that program owners contributed evidence of program success or weakness and identified applicable self-assessments, quality assurance audits, peer evaluations, and NRC reviews.

LRA Section B.0.4 also describes the process for review of future plant-specific and industry operating experience, which is applicable to the AMPs described in LRA Sections B.1.1 through B.1.44. The LRA states that external industry operating experience is screened, evaluated, and acted on to prevent or mitigate the consequences of similar age-related degradation. The sources of this external operating experience include NRC generic communications and other documents, such as reports made in accordance with 10 CFR Part 21, "Reporting of Defects and Noncompliance," LERs, and nonconformance reports. The LRA also states that internal operating experience may include items such as event investigations, trending reports, lessons learned from in-house events, self-assessments, and the 10 CFR Part 50, Appendix B, corrective action process. In addition, the LRA states that the procedures for the evaluation of these sources of operating experience will remain in-place as GGNS continues operation through the license renewal period. These procedures implement two existing programs, the Operating Experience Program (OEP) and the CAP, which monitor, on an ongoing basis, industry and plant-specific operating experience, including, but not limited to, future operating experience related to the effects of aging on in-scope SCs. The LRA further states that the evaluations completed under the OEP and CAP ensure that the AMPs will continue to be effective in managing the aging effects for which they are credited.

3.0.5.2 Staff Evaluation

3.0.5.2.1 Overview

In accordance with requirements of 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. SRP-LR, Appendix A, describes 10 elements of an acceptable AMP, and Element 10, "operating experience," is described in SRP-LR Section A.1.2.3.10. Subsequent to receipt of the LRA, on March 16, 2012, the staff issued Final License Renewal Interim Staff Guidance (LR-ISG), LR-ISG-2011-05, "Ongoing Review of Operating Experience." This LR-ISG provides interim revisions to the SRP-LR to clarify the staff's acceptance criteria and review procedures with respect to the ongoing review of operating experience and also provides revisions to the GALL Report to make the AMP descriptions therein consistent with the SRP-LR guidance for acceptable AMPs. LR-ISG-2011-05, Appendix A, identifies changes to the SRP-LR and GALL Report. Specifically, LR-ISG-2011-05, Appendix A, revises the three operating experience criteria in SRP-LR Section A.1.2.3.10 to:

(1) Consideration of future plant-specific and industry operating experience relating to AMPs should be discussed. The ongoing review of operating experience may identify areas where AMPs should be enhanced or new AMPs developed. As such, an applicant should ensure that it has adequate processes to monitor and evaluate plant-specific and industry operating experience related to aging management to ensure that the AMPs are effective in managing the aging effects for which they are credited. The AMPs are informed by this review of operating experience on an ongoing basis, regardless of the AMP's implementation schedule. The ongoing review of operating experience information should provide objective evidence to support the conclusion that the effects of aging are managed adequately so that the structure- and component- intended function(s) will be maintained during the period of extended operation.

(2) Currently available operating experience with existing programs should be discussed. The operating experience of 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 not been fully effective 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 managed adequately so that the structure- and component-intended function(s) will be maintained during the period of extended operation.

(3) Currently available operating experience applicable to new programs should also be discussed. For new AMPs that have yet to be implemented at an applicant's facility, the programs have not yet generated any operating experience. However, there may be other relevant plant-specific or generic industry operating experience that is relevant to the program elements, even though the operating experience was not identified through implementation of the new program. Thus, when developing the elements for new programs, an applicant should consider the impact of relevant operating experience from implementation of its existing AMPs and from generic industry operating experience.

SER Section 3.0.3 discusses the staff's review of the second and third attributes, which concern currently available 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.

3.0.5.2.2 Consideration of Future Operating Experience

Itemized Change No. 7 in LR-ISG-2011-05 Appendix A establishes a new SRP-LR Section A.4. This section provides a framework of ongoing activities to address operating experience concerning age-related degradation and aging management during the term of the renewed operating license to ensure that the effects of aging are adequately managed. The staff evaluated the details of the applicant's ongoing operating experience review activities, as described in LRA Section B.0.4, against the staff position described in SRP-LR Section A.4.2.

Based on its review, the staff determined that LRA Section B.0.4 provides a general description of how the applicant gathered and considered operating experience in preparing the LRA, and LRA Sections B.1.1 through B.1.44 summarize the specific operating experience considered for each AMP. The LRA also states that the CAP and OEP will be used to evaluate operating experience to ensure that the AMPs will continue to be effective in managing the aging effects for which they are credited. However, the staff determined that the LRA does not provide specific details as to how the CAP and OEP will be used to monitor operating experience related to aging on an ongoing basis. The staff also determined that the LRA does not state whether new AMPs will be developed, if necessary.

By letter dated July 27, 2012, the staff issued RAI 3.0.5-1 requesting that the applicant describe the programmatic activities that will be used to continually identify aging issues, evaluate them, and, as necessary, enhance the AMPs or develop new AMPs for license renewal. The staff also asked the applicant to indicate whether these activities are consistent with the guidance in LR-ISG-2011-05, and if they are not, the staff requested the applicant to provide the basis for its conclusion that the programmatic activities will ensure that operating experience will be reviewed on an ongoing basis to address age-related degradation and aging management during the term of the renewed license.

The applicant responded to RAI 3.0.5-1 by letter dated August 23, 2012. The applicant provided further information to describe how it processes relevant site and industry operating experience on an ongoing basis under its CAP and OEP. The applicant stated that it uses the OEP to monitor industry operating experience and listed some typical industry operating experience sources. The applicant described the process for screening incoming operating experience items and initiating written reviews for issues that could have a potential impact on the plant. The applicant also described the CAP, which is used to monitor plant-specific operating experience and evaluate industry operating experience relevant to the plant. A list of typical plant-specific operating experience sources monitored under the CAP was also provided. In addition, the applicant described how age-related conditions are coded and trended. Evaluations of age-related conditions and extent-of-condition reviews were described, along with corrective actions for enhancement of AMPs or development of new AMPs. The applicant explained that training requirements for personnel responsible for processing operating experience are based on the complexity of the job performance requirements and assigned responsibilities. In summary, the applicant stated that it considers these activities to be consistent with the framework in LR-ISG-2011-05.

The staff reviewed the applicant's response to RAI 3.0.5-1. Although the response indicates that the applicant's programmatic activities for the ongoing review of operating experience are consistent with LR-ISG-2011-05, the staff found that the response does not fully address or is not clear on the extent to which these activities are consistent with each of the further review areas described in LR-ISG-2011-05, Appendix A, Itemized Change No. 7. Therefore, the staff could not confirm that the operating experience review activities are actually consistent with the guidance in the LR-ISG. By letter dated November 5, 2012, the staff issued RAI 3.0.5-1a requesting that the applicant further describe its operating experience review activities to demonstrate how they align with several of the further review areas in LR-ISG-2011-05. The specific areas on which the staff requested further information concerned the review of certain types of industry guidance documents, identification and trending of age-related issues in the CAP, information considered in the operating experience evaluations, evaluation of AMP implementation results, training of personnel, and guidelines for reporting plant-specific operating experience to the industry.

By letter dated November 29, 2012, the applicant provided further information in response to RAI 3.0.5-1a. The staff evaluated the information provided in this response, together with the information provided in the applicant's response to RAI 3.0.5-1, in accordance with the guidance in SRP-LR Section A.4.2 on "Acceptable Use of Existing Programs" and "Areas of Further Review." The staff's evaluations with respect to these two sections of guidance follow in SER Sections 3.0.5.2.3 and 3.0.5.2.4, respectively. As a result of its review of the applicant's responses to RAIs 3.0.5-1 and RAI 3.0.5-1a, the staff could not determine whether the programmatic activities associated with the identification of age-related operating experience, evaluation of AMP implementation results, content of personnel training, and operating experience reporting were fully consistent with the guidelines in SRP-LR Section A.4.2, as claimed by the applicant. The staff identified these areas as the subject of Open Item 3.0.5-1. SER Section 3.0.5.2.4 discusses their closure.

3.0.5.2.3 Acceptable Use of Existing Programs

SRP-LR Section A.4.2 describes existing programs generally acceptable to the staff for the capture, processing, and evaluation of operating experience concerning age-related degradation and aging management during the term of a renewed operating license. The acceptable programs are those relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," of NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980. SRP-LR Section A.4.2 additionally states that, as part of meeting the requirements of NUREG-0737, Item I.C.5, the applicant's operating experience program should rely on active participation in the Institute of Nuclear Power Operations (INPO) operating experience program (formerly the INPO Significant Event Evaluation and Information Network (SEE-IN) program endorsed in GL 82-04, "Use of INPO SEE-IN Program").

The response to RAI 3.0.5-1 states that the applicant uses its OEP to monitor industry operating experience, and the OEP implements the requirements NUREG-0737 Item I.C.5 and is consistent with INPO 10-006, Revision 1, “Operating Experience (OE) Program and Construction Experience (CE) Program Descriptions,” and INPO 97-011, “Guidelines for the Use of Operating Experience.” The response also states that the applicant uses its CAP to monitor plant-specific operating experience and evaluate industry operating experience relevant to the plant, and the CAP implements the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action.” Based on this information, the staff determined that the applicant’s existing CAP and OEP are consistent with the programs described in SRP-LR Section A.4.2 and therefore are generally acceptable for capturing, processing, and evaluating age-related operating experience.

3.0.5.2.4 Areas of Further Review

Notwithstanding the general acceptability of the applicant’s CAP and OEP, certain areas of the applicant’s operating experience review activities are also subject to further staff review as described in SRP-LR Section A.4.2. The staff’s reviews of these areas follow.

Application of Existing Programs and Procedures to the Processing of Operating Experience Related to Aging. SRP-LR Section A.4.2 states that the programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and NUREG-0737, Item I.C.5, should not preclude the consideration of operating experience on age-related degradation and aging management. In response to RAI 3.0.5-1, the applicant stated that the CAP is used to address a broad range of problems and areas for improvement, such as conditions adverse to quality and minor problems that could be precursors to more significant events. The applicant also specifically stated that the CAP is used to address equipment degradation due to the effects of aging, including when the degradation is identified from an initial evaluation of industry operating experience under the OEP. Additionally, in response to RAI 3.0.5-1a, the applicant stated that the written definition of operating experience in the OEP does not restrict the sources of operating experience, and information from various internal and industry sources is identified and processed to obtain lessons learned applicable to managing the effects of aging.

The staff reviewed the information provided in these responses and determined that the applicant’s CAP and OEP would not preclude the capture and evaluation of operating experience related to aging because (a) the scope of the OEP covers all potential sources of industry operating experience, and (b) the CAP is specifically used to address age-related degradation and aging management issues, whether identified from a plant-specific source or from the review of an industry source. The applicant’s use of these programs for processing operating experience is therefore consistent with the guidance in SRP-LR Section A.4.2. SRP-LR Section A.4.2 also states that the applicant should use the option described in SRP-LR Appendix A.2 to expand the scope of the 10 CFR Part 50, Appendix B, program to include nonsafety-related structures and components. As discussed in SER Section 3.0.4, the staff determined that the applicant’s inclusion of nonsafety-related structures and components within the scope of its 10 CFR Part 50, Appendix B, program is consistent with the guidance in SRP-LR Appendix A.2 and therefore also consistent with the guidance in SRP-LR Section A.4.2.

Consideration of Industry Guidance Documents as Operating Experience. SRP-LR Section A.4.2 states that revisions to the GALL Report should be considered as a source of industry operating experience and evaluated accordingly. In response to RAI 3.0.5-1a, the applicant confirmed that it reviews revisions of the GALL Report as a source of industry operating experience. SRP-LR Section A.4.2 also states that NRC and industry guidance documents and standards applicable to aging management should be considered as sources of operating experience. In response to RAI 3.0.5-1a, the applicant stated that the OEP does not restrict the review of industry operating experience to sources only from a predetermined list. In addition to specifically listed sources of industry operating experience, the applicant stated that its policies and procedures contain written plans and expectations for identifying and processing other sources of information, when they concern industry guidance or standards applicable to aging management. The staff reviewed the information provided in this response and determined that the applicant will consider the impacts of industry guidance documents on its aging management activities because the applicant's operating experience reviews will cover appropriate NRC and industry guidance documents and standards applicable to aging management, including revisions to the GALL Report. The applicant's consideration of industry guidance documents as operating experience is therefore consistent with the guidance in SRP-LR Section A.4.2.

<u>Screening of Incoming Operating Experience</u>. SRP-LR Section A.4.2 states that all incoming plant-specific and industry operating experience should be screened to determine whether it may involve age-related degradation or impacts to aging management activities. The applicant's response to RAI 3.0.5-1 outlines its operating experience screening and evaluation process. For industry operating experience, the applicant explained that a team of operating experience coordinators screens incoming items for impact on the applicant's fleet of plants. If the initial evaluation identifies certain conditions involving age-related issues, then further documentation is required as part of the CAP. The applicant stated that the CAP is used to evaluate both plant-specific and industry operating experience relevant to the plant, and extent-of-condition reviews are used to determine the scope of corrective actions, which include enhancement of AMPs or development of new AMPs as appropriate. The staff reviewed the information provided in this response and determined that the applicant's operating experience review processes are acceptable because they will include screening of all new operating experience items to identify and evaluate items that have the potential to affect the aging management activities. The applicant's screening of plant-specific and industry operating experience is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

<u>Identification of Operating Experience Related to Aging</u>. SRP-LR Section A.4.2 states that an identification code should be used in the CAP to identify operating experience concerning age-related degradation applicable to the plant. The SRP-LR also states that the associated entries should be periodically reviewed and any adverse trends should receive further evaluation. The applicant's identification of age-related operating experience was one of the subject areas of Open Item 3.0.5-1.

In response to RAI 3.0.5-1a, the applicant stated that it periodically reviews information in its CAP to identify and evaluate adverse trends. The applicant also stated that aging is a contributing factor in SSC degradation and, therefore, issues specific only to aging are rare. As such, the applicant stated that it does not have trend codes specifically for identifying aging issues; however, the applicant indicated that it does use several trend codes to track issues in which aging is a factor. The applicant specifically described three such codes: (1) code "CA," which is used to identify deviations from the licensing or design basis caused by the effects of aging or other issues, (2) code "EO," which is used to identify equipment or system problems due to aging or other issues not attributed to inadequate maintenance, and (3) code "EV," which is used to identify aging issues for plant buildings and structures.

The staff reviewed the information provided in response to RAI 3.0.5-1a and determined that the applicant's process for evaluating adverse trends is consistent with the guidance in SRP-LR Section A.4.2 because the applicant will identify such trends through periodic reviews of information in its CAP. However, the staff determined that the trend codes described by applicant are not consistent with the guidance in SRP-LR Section A.4.2 because they only cover general operational issues and do not provide for the comprehensive identification and categorization of aging specific issues for all in-scope SSCs. As such, the staff determined that the applicant did not have the means, at a programmatic level, to identify, track, and trend plant issues that are specific to aging. By letter dated March 12, 2013, the staff issued RAI 3.0.5-1b requesting that the applicant provide further information as to why the operating experience review activities provide for the adequate identification of operating experience involving age-related degradation and aging management.

By letter dated April 15, 2013, the applicant responded to RAI 3.0.5-1b. In its response, the applicant reiterated its position that the trend codes and periodic review process previously described in its response to RAI 3.0.5-1a demonstrate consistency with the guidance in LR-ISG-2011-05 for identification of age-related operating experience.

The staff reviewed the applicant's response to RAI 3.0.5-1b. The staff noted that the intent of LR-ISG-2011-05, which establishes SRP-LR Section A.4.2, is to use a single code or set of codes to specifically identify age-related issues so that an applicant can evaluate the potential impact that these issues may have on the effectiveness of its AMPs. Per the definitions provided in the applicant's response to RAI 3.0.5-1a, code "EV" partially meets this intent because it specifically captures age-related issues for plant buildings and structures. However, the applicant did not describe similar codes that would categorically capture age-related issues for other in-scope SCs, such as those in mechanical or electrical systems. The applicant's codes "CA" and "EO" cover these other categories of in-scope SSCs; however, the staff determined that the intended application of these codes is unclear because they may be used to identify items that are not age related, along with age-related items. By letter dated September 12, 2013, the staff issued RAI 3.0.5-1c. If the applicant intended to demonstrate consistency with the guidance in LR-ISG-2011-05, the staff requested that the applicant describe codes that will be used to specifically identify age-related issues. Alternatively, the staff asked the applicant to describe how the operating experience review activities provide for the adequate consideration of operating experience involving age-related degradation and aging management to maintain the effectiveness of the AMPs.

By letter dated October 11, 2013, the applicant responded to RAI 3.0.5-1c. The applicant stated that it established a new code, "FE25," for the identification of all aging management issues at the plant. The staff reviewed the intended application of this code and determined that it is consistent with the guidance in LR-ISG-2011-05, because it provides for the specific capture of aging issues and categorically covers all in-scope SSCs. As such, the staff determined that the applicant's activities for identifying age-related operating experience are consistent with the guidance in SRP-LR Section A.4.2. The staff's concerns regarding the applicant's identification of age-related operating experience, as in described in RAIs 3.0.5-1b and 3.0.5-1c, are resolved and the related area of Open Item 3.0.5-1 is closed.

<u>Information Considered in Operating Experience Evaluations</u>. SRP-LR Section A.4.2 states that operating experience identified as involving aging should receive further evaluation based on the consideration of information such as the affected SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. The SRP-LR also states that actions should be initiated within the CAP to either enhance the AMPs or develop and implement new AMPs if it is found,

through an operating experience evaluation, that the effects of aging may not be adequately managed. In response to RAI 3.0.5-1a, the applicant confirmed that its evaluations of age-related operating experience include the consideration of information such as the affected SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. Also, in response to RAI 3.0.5-1, the applicant stated that the CAP, which implements the requirements of 10 CFR Part 50, Appendix B, is used to evaluate both plant-specific and industry operating experience relevant to the plant. The applicant further stated that, under the CAP, corrective actions resulting from an operating experience evaluation include the enhancement of AMPs or the development of new AMPs, as appropriate. The staff reviewed the information provided in these responses and determined that the applicant's evaluations of age-related operating experience will include the assessment of appropriate information to determine potential impacts on the aging management activities. The staff also determined that the applicant will use its CAP to implement any changes necessary to manage the effects of aging, as determined through its operating experience evaluations. Therefore, the staff finds that the information considered in the applicant's operating experience evaluations and use of its CAP to ensure that the effects of aging are adequately managed is consistent with the guidance in SRP-LR Section A.4.2.

<u>Evaluation of AMP Implementation Results</u>. SRP-LR Section A.4.2 states that the results of implementing the AMPs, such as data from inspections, tests, and analyses, should be evaluated regardless of whether the acceptance criteria of the particular AMP have been met. SRP-LR Section A.4.2 also states that actions should be initiated within the plant CAP to either enhance the AMPs or develop and implement new AMPs, if these evaluations indicate that the effects of aging may not be adequately managed. The applicant's evaluation of AMP implementation results was one of the subject areas of Open Item 3.0.5-1.

In response to RAI 3.0.5-1, the applicant stated that it considers the results of inspections performed under the AMPs to be a source of operating experience under the CAP. The applicant stated that its evaluations of these results include consideration of the need to adjust the frequency of future inspections, whether new or different inspections are needed, and whether the inspections include an adequate depth and breadth of component, material, and environment combinations. The applicant further stated that, under the CAP, it uses extent-of-condition reviews to determine the scope of corrective actions, which include the enhancement of AMPs or the development of new AMPs, as appropriate. Additionally, in response to RAI 3.0.5-1a, the applicant stated that it has conservatively established the acceptance criteria for its AMPs to identify the thresholds for taking additional action. The applicant further stated that acceptable implementation results confirm the effectiveness of the program. In these instances, the applicant stated that an evaluation is not needed to determine whether changes to the AMPs are needed.

The staff reviewed the information provided in response to RAIs 3.0.5-1 and 3.0.5-1a and determined that, although the applicant will consider the AMP implementation results as a source of plant-specific operating experience, its evaluation activities are not fully consistent with the guidance in SRP-LR Section A.4.2 because the applicant only plans to evaluate the implementation results when they do not meet the applicable acceptance criteria. As such, the staff determined that the applicant did not have a process to assess the overall performance and effectiveness of the AMPs. The staff noted that not all implementation results would necessitate a change to an AMP, but an evaluation of acceptable implementation results could be used, for example, to determine the continued appropriateness of the program's acceptance criteria. As part of RAI 3.0.5-1b, the staff requested that the applicant provide further information as to how its assessments of AMP implementation are performed to determine if the effects of aging are adequately managed.

In response to RAI 3.0.5-1b, the applicant provided additional information about its approach to evaluating AMP implementation results. The applicant stated that it will perform periodic assessments of AMP implementation to evaluate the effectiveness of the AMPs. The applicant explained that these assessments will include focused self-assessments, independent assessments, external assessments, ongoing assessments, or snapshot assessments. In addition, the applicant stated that program health reports will be prepared to periodically monitor how effective the AMPs are at maintaining the material condition of components. According to the applicant, these assessments and reports will include evaluations of parameter trends, which will support decisions on whether the frequency of future inspections should be adjusted, whether new inspections should be established, or whether the inspection scope or acceptance criteria should be adjusted or expanded. The applicant stated that, if these assessments indicate that the effects of aging may not be adequately managed, it will initiate an action in its CAP to either enhance the AMPs or develop and implement new AMPs.

The staff reviewed the additional information provided in response to RAI 3.0.5-1b and determined that the applicant's treatment of AMP implementation results as operating experience is acceptable because the applicant will evaluate these results and use the information to determine whether to adjust its aging management activities. The staff also determined the applicant's periodic assessment activities will appropriately cover the evaluation of AMP implementation results, even when these results have met the applicable acceptance criteria of the AMPs. As such, the staff determined that the applicant's activities for evaluating the AMP implementation results are consistent with the guidance in SRP-LR Section A.4.2. The staff's concern regarding the applicant's evaluation of AMP implementation results, as described in RAI 3.0.5-1b, is resolved and the related area of Open Item 3.0.5-1 is closed.

Training. SRP-LR Section A.4.2 states that training on age-related degradation and aging management should be provided to those personnel responsible for implementing the AMPs and those personnel that may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. SRP-LR Section A.4.2 also states that the training should occur on a periodic basis and include provisions to accommodate the turnover of plant personnel. The content of the applicant's personnel training program was one of the subject areas of Open Item 3.0.5-1.

In response to RAI 3.0.5-1a, the applicant described the training activities that will be associated with processing and evaluating operating experience. The applicant stated that it will provide training to those personnel who are responsible for implementing the AMPs or who submit operating experience to the CAP and OEP. The applicant also stated that it will provide training to those personnel who screen operating experience items, evaluate them, and assign or otherwise process them for evaluation. According to the applicant, the training activities will include instruction on applicable references and databases; discussion of relevant codes, standards, inspection methods, and evaluation techniques; review of applicable operating experience; and demonstration of the ability to develop an inspection plan and evaluate the results. The applicant also stated that it will schedule this training on a recurring basis to accommodate the turnover of plant personnel and the need for new training content.

The staff reviewed the information provided in response to RAI 3.0.5-1a and determined that the scope of key personnel covered by the applicant's training activities is consistent with the guidelines in SRP-LR Section A.4.2. The staff also determined that the applicant's plans to provide recurring training and training when personnel turn over are also consistent with these guidelines. However, the applicant did not describe how the content of the training includes topics on age-related degradation and aging management; therefore, it was not clear to the staff whether the applicant's training activities were fully consistent with guidance in SRP-LR Section A.4.2. As part of RAI 3.0.5-1b, the staff requested that the applicant provide further information on the content of its personnel training program.

In response to RAI 3.0.5-1b, the applicant provided an outline to illustrate how its training activities cover topics on aging management and age-related degradation. Per this outline, the applicant's training activities include a combination of classroom training, required reading, and mentored skills demonstrations. The response indicates that the training covers areas such as understanding and identifying various aging effects, knowledge of relevant industry operating experience documents, and knowledge of site-specific AMPs and procedures.

The staff reviewed the response to RAI 3.0.5-1b and determined that the additional information provided by the applicant acceptably demonstrates that its training program covers topics on age-related degradation and aging management. As such, the staff determined that the applicant's training activities are consistent with the guidance in SRP-LR Section A.4.2. The staff's concern regarding the applicant's training activities, as in described in RAI 3.0.5-1b, is resolved and the related area of Open Item 3.0.5-1 is closed.

Reporting Operating Experience to the Industry. SRP-LR Section A.4.2 states that guidelines should be established for reporting plant-specific operating experience on age-related degradation and aging management to the industry. The applicant's reporting of age-related operating experience was one of the subject areas of Open Item 3.0.5-1.

In response to RAI 3.0.5-1a, the applicant stated that it reports its plant-specific operating experience to the industry per the guidelines in INPO 12-009, "INPO Consolidated Event System." The applicant stated that this reporting includes findings of root cause investigation reports, LERs submitted under 10 CFR 50.73, and plant event notices submitted under 10 CFR 50.72. The applicant also stated that it submits reports after the discovery of other issues, including the failure of equipment and components to meet intended functions.

The staff reviewed the information provided in response to RAI 3.0.5-1a and determined that the applicant's reporting of plant-specific operating experience was not consistent with the guidance in SRP-LR Section A.4.2 because the applicant only described general reporting criteria that are not specific to circumstances involving age-related degradation and aging management. As such, the staff determined that the applicant did not have a process to consistently identify and communicate this kind of operating experience. As part of RAI 3.0.5-1b, the staff requested that the applicant provide further information as to how its OEP includes guidelines for reporting age-related operating experience.

In response to RAI 3.0.5-1b, the applicant provided additional information about its process for reporting plant-specific operating experience. The applicant stated that its OEP includes specific guidelines for reporting operating experience involving age-related degradation or aspects of programs that manage the effects of aging. The applicant also stated that the reporting is accomplished in accordance with the guidelines from INPO 12-009. For example, the applicant stated that it reports findings from root cause investigations involving age-related degradation and leaks or adverse inspection findings for buried or underground piping. In addition, the applicant stated that INPO 12-009 includes several cause categories that cover aging issues, such as “erosion/corrosion process,” “equipment aging - nonmetallic,” and “equipment aging - metallic.”

The staff reviewed the additional information provided in the applicant’s response to RAI 3.0.5-1b. The staff noted that the intent of SRP-LR Section A.4.2 is to establish reporting guidelines for communicating noteworthy plant-specific operating experience that specifically involves age-related degradation or aging management issues. However, the current reporting criteria in INPO 12-009 do not specifically address aging issues or only cover limited situations involving aging. As such, the staff determined that these criteria do not provide for the comprehensive identification and subsequent reporting of age-related operating experience. In RAI 3.0.5-1c, if the applicant intended to demonstrate consistency with the guidance in SRP-LR Section A.4.2, the staff requested that the applicant describe guidelines specifically for identifying circumstances in which plant-specific operating experience involving age-related degradation and aging management would be reported to the industry. Alternatively, the staff requested that the applicant describe how the operating experience review activities would provide for the adequate consideration of operating experience involving age-related degradation and aging management to maintain the effectiveness of the AMPs.

In response to RAI 3.0.5-1c, the applicant reiterated its position that its current procedures provide for the reporting of plant-specific operating experience involving age-related degradation and aging management, consistent with the guidance in SRP-LR Section A.4.2, because the procedures are in accordance with INPO 12-009. As additional support for its position, the applicant stated that the effectiveness of the INPO operating experience program is demonstrated by the numerous examples of industry operating experience involving age-related degradation that have been identified and reported.

The staff reviewed the applicant’s response to RAI 3.0.5-1c and determined that the additional information provided by the applicant does not demonstrate consistency with the guidance in SRP-LR Section A.4.2 regarding operating experience reporting. In particular, the applicant did not describe any reporting criteria beyond those specified in INPO 12-009, and the staff determined that this document does not currently include criteria that would categorically cover the reporting of noteworthy issues involving age-related degradation and aging management. In addition, although the INPO 12-009 cause codes identified by the applicant would cover a broad range of age-related issues, under the INPO process they do not constitute a set of reporting criteria, because they are only applied after it been determined that a given issue is reportable. Notwithstanding, the staff determined that it is not necessary for the applicant to establish operating experience reporting criteria per the guidelines of SRP-LR Section A.4.2, because the reporting of age-related operating experience to other licensees would not directly facilitate the applicant’s ability to maintain the effectiveness of its own AMPs. Therefore, such reporting is not needed to demonstrate that the effects of aging 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). As such, the staff determined that it is acceptable for the applicant to not be consistent with this particular area of SRP-LR Section A.4.2.

However, the staff continues to believe that it is prudent to establish specific reporting guidelines for noteworthy issues that are age related. Although the current reporting criteria in INPO 12-009 do not necessarily exclude these issues, they also do not specifically cover them, either. Therefore, some potentially noteworthy aging issues may not be communicated, because they that do not fall under the current reporting guidelines. The staff notes that the industry has recognized this issue as a potential area for improvement in the INPO operating experience program, and the industry has begun an initiative to revise INPO 12-009 accordingly. A draft of the revised reporting guidelines was discussed with the staff during a public meeting held on July 29, 2014. The staff supports this industry initiative and notes that, if the proposed changes are adopted, they would fulfill the intent the operating experience reporting criterion in LR-ISG-2011-05.

The staff finds that establishing operating experience reporting guidelines specific to age-related issues is a best practice and is not necessary to fulfill the requirements of 10 CFR 54.21(a)(3). Accordingly, the staff's concerns regarding the applicant's reporting of age-related operating experience, as in described in RAIs 3.0.5-1b and 3.0.5-1c, are resolved and the related area of Open Item 3.0.5-1 is closed.

<u>Schedule for Implementing the Operating Experience Review Activities</u>. SRP-LR Section A.4.2 states that any enhancements to the existing operating experience review activities should be put in place no later than the date when the renewed operating license is issued. In RAI 3.0.5-1a, the staff requested that the applicant identify any such enhancements and provide a schedule for their implementation, including a justification if the implementation date is later than the date when the renewed operating license is scheduled to be issued, if approved. In response, the applicant stated that there are no enhancements to its existing activities. The staff reviewed the applicant's response and determined that the guidance in SRP-LR Section A.4.2 does not apply, because the applicant is currently implementing all of the operating experience review activities described in its LRA. Accordingly, there are no enhancements.

SRP-LR Section A.4.2 also states that the operating experience review activities should be implemented on an ongoing basis throughout the term of the renewed license. By letter dated August 23, 2012, as revised by letter dated October 11, 2013, the applicant amended the UFSAR supplement in the LRA to include a summary description of the ongoing operating experience review activities. As discussed in SER Section 3.0.5.3, the staff determined that this summary description is sufficiently comprehensive to describe the applicant's programmatic activities for the ongoing review of operating experience. On issuance of a renewed license in accordance with 10 CFR 54.31(c), the summary description will be incorporated into the plant's CLB and, at that time, the applicant will need to conduct its operating experience review activities accordingly. The staff finds this implementation schedule acceptable, because the applicant will implement the operating experience review activities on an ongoing basis throughout the term of the renewed operating license. This ongoing implementation is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

3.0.5.2.5 Summary

Based on its review of the applicant's responses to RAIs 3.0.5-1, 3.0.5-1a, 3.0.5-1b, and 3.0.5-1c, the staff determined that the applicant's programmatic activities for the ongoing review of operating experience are consistent with the guidance in SRP-LR Section A.4.2, with the exception of the applicant's operating experience reporting activities, which are an acceptable departure from the guidance. Therefore, the staff determined that these activities 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) the enhancement of AMPs 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. Based on completion of the staff's review and the general consistency of the applicant's operating experience review activities with the guidance in SRP-LR Section A.4.2, as established in LR-ISG-2011-05, the staff's concerns described in RAIs 3.0.5-1, 3.0.5-1a, 3.0.5-1b, and 3.0.5-1c are resolved. Open Item 3.0.5-1 is closed.

3.0.5.3 UFSAR Supplement

LRA Section A.1 provides the UFSAR supplement summary description of the applicant's operating experience review activities. It states that the OEP and the CAP help to ensure the continued effectiveness of the AMPs through evaluations of operating experience. The summary description states that the OEP implements the requirements of NUREG-0737, Item I.C.5, and that it is used to evaluate site, fleet, and industry operating experience. The summary description also states that the CAP implements the requirements of 10 CFR Part 50, Appendix B, and that it is used to evaluate and effect appropriate actions in response to operating experience that indicates a condition adverse to quality or a nonconformance.

SRP-LR Section A.4.2, as established in LR-ISG-2011-05, states that the programmatic activities for the ongoing review of plant-specific and industry operating experience concerning age-related degradation and aging management should be described in the UFSAR supplement. LR-ISG-2011-05 also revises SRP-LR Table 3.0-1 to include sample summary description language for the UFSAR supplement. The staff reviewed the content of the applicant's summary description against the content from the example in the SRP-LR. Based on its review, the staff determined that the LRA did not specifically describe how the CAP and OEP address aging, so in RAI 3.0.5-1, the staff requested that the applicant further describe how the activities conducted under these programs capture aging issues, evaluate them, and, as necessary, initiate actions to enhance the AMPs or develop new AMPs. The staff also requested that the applicant describe in the UFSAR supplement how operating experience will be reviewed on an ongoing basis to address age-related degradation and aging management during the period of extended operation.

In response to RAI 3.0.5-1, the applicant amended the UFSAR supplement to include a new LRA Section A.0.1 to describe the details of its programmatic activities for the ongoing review of operating experience. Based on its responses to RAIs 3.0.5-1a and 3.0.5-1b, the applicant subsequently amended LRA Section A.0.1 by letters dated November 29, 2012, and April 15, 2013, respectively. The staff reviewed the revised summary description in conjunction with its review of the applicant's responses to RAIs 3.0.5-1a and 3.0.5-1b. Based on its review, the staff determined that the applicant's RAI responses describe certain key operating experience review activities; however, these activities were not addressed in LRA Section A.0.1. Specifically, the staff noted that the summary description did not address: (a) the applicant's plans to review future revisions of the GALL Report as a source of industry operating experience, and (b) that the operating experience evaluations determine potential impacts on the aging management activities, based on consideration of the affected plant SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. By letter dated September 12, 2013, the staff issued RAI 3.0.5-1d requesting that the applicant either revise LRA Section A.0.1 to summarize these activities or provide a justification for not including such a summary description in the UFSAR supplement.

By letter dated October 11, 2013, the applicant responded to RAI 3.0.5-1d by further amending LRA Section A.0.1 to capture its plans for reviewing future revisions of the GALL Report and the specific information that it will consider when evaluating operating experience items with the potential to involve age-related degradation. The staff reviewed the content of the revised LRA Section A.0.1 against the sample language in SRP-LR Table 3.0-1. Based on its review, the staff determined that the content of the applicant's summary description, as amended by letter dated October 11, 2013, is consistent with the example and also sufficiently comprehensive to describe the applicant's programmatic activities for evaluating operating experience to maintain the effectiveness of the AMPs. Therefore, the staff finds the applicant's UFSAR supplement summary description acceptable. The staff's concern described in RAI 3.0.5-1d is resolved.

3.0.5.4 Conclusion

Based on its review of the applicant's programmatic activities for the ongoing review of operating experience, the staff concludes that the applicant has demonstrated that operating experience will be reviewed to ensure that the effects of aging 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). The staff also reviewed the UFSAR 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 section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and reactor coolant system components and component groups of:

- reactor vessel
- reactor vessel internals
- reactor coolant pressure boundary
- miscellaneous RCS systems in scope for 10 CFR 54.4(a)(2)

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the reactor vessel, reactor vessel internals, and reactor coolant system components and component groups. LRA Table 3.1.1, "Summary of Aging Management Programs for the Reactor Coolant System Evaluated in Chapter IV of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the reactor vessel, reactor vessel internals, and reactor coolant 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.

3.1.2 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, internals and reactor coolant 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 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 which 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 GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to 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 due to 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	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 due to 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)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1-4)	Cumulative fatigue damage due to 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 due to 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	Not applicable to BWRs (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 coolant pressure boundary components: piping, piping components, and piping elements exposed to reactor coolant (3.1.1-6)	Cumulative fatigue damage due to 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 due to 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)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 steam generator components exposed to reactor coolant (3.1.1-8)	Cumulative fatigue damage due to 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 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 due to 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 due to 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/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles (3.1.1-11)	Cumulative fatigue damage due to 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 3.1.2.2.2)
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 due to general, pitting, and crevice corrosion	Chapter XI.M1, "ASME 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)
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 due to 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 due to 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))

Component Group (SRP-LR Item No.)	Aging Effect/ 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 vessel internal components exposed to reactor coolant and neutron flux (3.1.1-15)	Reduction in ductility and fracture toughness due to 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))
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (3.1.1-16)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	A plant-specific AMP is to be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC in the vessel flange leak detection line	Yes	Water Chemistry Control – BWR Program and One-Time Inspection	See SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-17)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M1, "ASME 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 GGNS (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 due to 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	See SER Section 3.1.2.2.5)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to stress corrosion cracking	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.6(1))
Cast austenitic stainless steel Class 1 piping, piping components, and piping elements exposed to reactor coolant (3.1.1-20)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry" and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific AMP	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 due to cyclic loading	Chapter XI.M1, "ASME 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 GGNS (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 due to erosion	A plant-specific AMP 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 due to stress corrosion cracking and irradiation--assisted stress corrosion cracking	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/ 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 due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to 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 due to primary water stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	Yes	Not applicable	Not applicable to BWRs (see SER Sections 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 due to 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/ 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 due to stress corrosion cracking and fatigue	A plant-specific AMP 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 due to wear	A plant-specific AMP 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 due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation--assisted stress corrosion cracking	Chapter XI.M1, “ASME 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	Not applicable	Not applicable to GGNS (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy penetration: drain line exposed to reactor coolant (3.1.1-30)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, cyclic loading	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to GGNS (see SER Section 3.1.2.1.1)
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-31)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to GGNS (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to wear	Chapter XI.M1, "ASME 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 due to stress corrosion cracking	Chapter XI.M1, "ASME 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 due to stress corrosion cracking	Chapter XI.M1, "ASME 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 due to cyclic loading	Chapter XI.M1, "ASME 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 due to cyclic loading	Chapter XI.M1, "ASME 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 due to wear	Chapter XI.M1, "ASME 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/ 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 due to thermal aging embrittlement	Chapter XI.M1, "ASME 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	Inservice Inspection	Consistent with the GALL Report
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 due to stress corrosion cracking, intergranular stress corrosion cracking (for stainless steel only), and thermal, mechanical, and vibratory loading	Chapter XI.M1, "ASME 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	Inservice Inspection, Water Chemistry Control – BWR, and One-Time Inspection – 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 due to cyclic loading	Chapter XI.M1, "ASME 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 due to primary water stress corrosion cracking	Chapter XI.M1, "ASME 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 shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant (3.1.1-41)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation--assisted stress corrosion cracking	Chapter XI.M1, "ASME 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 GGNS (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended 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 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 due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, “ASME 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 due to pitting and crevice corrosion	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD” for Class 1 components, and Chapter XI.M2, “Water Chemistry”	No	Inservice Inspection, Water Chemistry Control – BWR, and One-Time Inspection – Small-Bore Piping	Consistent with the GALL Report
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 due to erosion	Chapter XI.M1, “ASME 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)
Nickel alloy and steel with nickel-alloy cladding reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-45)	Cracking due to primary water stress corrosion cracking	Chapter XI.M1, “ASME 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)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel-alloy, nickel-alloy welds and/or buttering control rod drive head penetration pressure housing or nozzles safe ends and welds (inlet, outlet, safety injection) exposed to reactor coolant (3.1.1-46)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, “ASME 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 control rod drive head penetration pressure housing exposed to reactor coolant (3.1.1-47)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, “ASME 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 due to 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)
Steel reactor coolant pressure boundary external surfaces or closure bolting exposed to air with borated water leakage (3.1.1-49)	Loss of material due to boric acid corrosion	Chapter XI.M10, “Boric Acid Corrosion”	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant >250 °C (>482 °F) (3.1.1-50)	Loss of fracture toughness due to thermal aging embrittlement	Chapter XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)”	No	Not applicable	See SER Section 3.1.2.1.1

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel-alloy B&W reactor internal components exposed to reactor coolant and neutron flux (3.1.1-51)	Cracking due to stress corrosion cracking, irradiation--assisted stress corrosion cracking, 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 due to stress corrosion cracking, irradiation--assisted stress corrosion cracking, 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 due to stress corrosion cracking, irradiation--assisted stress corrosion cracking, 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 due to 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)
Stainless steel thermal shield assembly, thermal shield flexures exposed to reactor coolant and neutron flux (3.1.1-55)	Cracking due to fatigue; Loss of material due to 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 due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to 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/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel-alloy B&W reactor internal components exposed to reactor coolant and neutron flux (3.1.1-58)	Loss of fracture toughness due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to 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 Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-59)	Loss of fracture toughness due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to 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 due to flow-accelerated corrosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
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 due to flow-accelerated corrosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength, low alloy steel, or stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-62)	Cracking due to stress corrosion cracking	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 due to general (steel only), pitting, and crevice corrosion or wear	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel closure bolting exposed to air – indoor uncontrolled (3.1.1-64)	Loss of material due to 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 control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-65)	Loss of material due to 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 control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-66)	Loss of preload due to 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 due to 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") due to 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)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 (3.1.1-69)	Cracking due to outer diameter stress corrosion cracking 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 due to primary water stress corrosion cracking	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 (3.1.1-71)	Cracking due to stress corrosion cracking 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 due to erosion, general, pitting, and crevice corrosion, ligament cracking due to 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 due to 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 due to 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 due to 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)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 (3.1.1-76)	Loss of material due to 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 tubes and sleeves exposed to secondary feedwater or steam (3.1.1-77)	Loss of material due to 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 due to stress corrosion cracking	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection,” or Chapter XI.M1, “ASME 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 due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry Control – BWR and One-Time Inspection	See SER Section 3.2.1.1
Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Section XI components) exposed to treated borated water >60 °C (>140 °F) (3.1.1-80)	Cracking due to stress corrosion cracking	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 due to stress corrosion cracking	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/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy pressurizer spray head exposed to reactor coolant (3.1.1-82)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	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 steam generator shell assembly exposed to secondary feedwater or steam (3.1.1-83)	Loss of material due to 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 due to general, pitting, and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry Control – BWR 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 due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry Control – BWR 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 due to stress corrosion cracking	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 due to 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 due to 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/ 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 due to 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 due to 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 due to stress corrosion cracking; loss of material due to general, pitting, and crevice corrosion, or wear (BWR)	Chapter XI.M3, “Reactor Head Closure Stud Bolting”	No	Reactor Head Closure Studs	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 due to stress corrosion cracking; loss of material due to 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 due to 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 due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M4, “BWR Vessel ID Attachment Welds,” and Chapter XI.M2, “Water Chemistry”	No	BWR Vessel ID Attachment Welds and Water Chemistry Control – BWR	Consistent with the GALL Report
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-95)	Cracking due to cyclic loading	Chapter XI.M5, “BWR Feedwater Nozzle”	No	BWR Feedwater Nozzle	Consistent with the GALL Report
Steel (with or without stainless steel cladding) control rod drive return line nozzles exposed to reactor coolant (3.1.1-96)	Cracking due to cyclic loading	Chapter XI.M6, “BWR Control Rod Drive Return Line Nozzle”	No	Not applicable	Not applicable to GGNS (see SER Section 3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to 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 Control – BWR, Inservice Inspection, and BWR CRD Return Line Nozzle	Consistent with the GALL Report (see SER Section 3.1.2.1.2)
Stainless steel or nickel alloy penetrations: instrumentation and standby liquid control exposed to reactor coolant (3.1.1-98)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, cyclic loading	Chapter XI.M8, "BWR Penetrations," and Chapter XI.M2, "Water Chemistry"	No	BWR Penetrations and Water Chemistry Control – BWR, and BWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.1.3)
Cast austenitic stainless steel; 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 due to 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 due to 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 due to 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 control rod drive assemblies control rod drive housing exposed to reactor coolant (3.1.1-102)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel Internals and Water Chemistry Control – BWR	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel Internals and Water Chemistry Control – BWR	Consistent with the GALL Report
X-750 alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-104)	Cracking due to intergranular stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals" for core plate, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to GGNS (see SER Section 3.1.2.1.1)
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 operating experience indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to GGNS (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 – indoors, uncontrolled (3.1.1-107)	None	None	NA	None	Consistent with the GALL Report

The staff's review of the reactor vessel, reactor vessel internals, and reactor coolant system 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, reactor vessel internals, and reactor coolant system 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 RV, RVI, and RCS components:

- Bolting Integrity
- BWR CRD Return Line Nozzle
- BWR Feedwater Nozzle
- BWR Penetrations
- BWR Stress Corrosion Cracking
- BWR Vessel ID Attachment Welds
- BWR Vessel Internals
- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Inservice Inspection
- Internal Surfaces in Miscellaneous Piping and Ducting Components
- Oil Analysis
- One-Time Inspection
- One-Time Inspection – Small-Bore Piping
- Reactor Head Closure Studs
- Reactor Vessel Surveillance
- Selective Leaching
- Water Chemistry Control – BWR
- Water Chemistry Control – Closed Treated Water Systems

LRA Tables 3.1.2-1 through 3.1.2-4 summarize AMRs for the reactor vessel, internals and reactor coolant system 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.

3.1.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.1.1, items 3.1.1-32 through 3.1.1-37, 3.1.1-40, 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 through 3.1.1-66, 3.1.1-68 through 3.1.1-78, 31.1.-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 that these items are not applicable to GGNS, which is a BWR.

For LRA Table 3.1.1, items 3.1.1-29, 3.1.1-31, 3.1.1-35, 3.1.1-36, 3.1.1-41, 3.1.1-96, 3.1.1-104, 3.1.1-105, the applicant claimed that the corresponding items in the GALL Report are 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, item 3.1.1-30, the applicant stated this item is not applicable because the applicant's reactor pressure vessel does not have a stainless steel or nickel alloy drain penetration. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for this item.

LRA Table 3.1.1, item 3.1.1-50 addresses cast austenitic stainless steel (CASS) Class 1 piping, piping component, and piping elements and CRD pressure housings exposed to a reactor coolant greater than 250 ºC (greater than 482 ºF) environment. The GALL Report recommends GALL Report AMP Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," to manage loss of fracture toughness due to thermal aging embrittlement for this component group.

The applicant stated that this item was not used for the LRA. The applicant stated that the only CASS components in the GGNS RCS are: (a) CASS pump casing; (b) CASS valve bodies greater than or equal to 4-inches NPS; and (c) the CASS main steam line flow elements (referred as flow restrictors in the UFSAR). The applicant stated that it manages loss of fracture toughness due to thermal aging embrittlement in the applicable CASS pump casings and valve bodies using LRA AMR item 3.1.1-38 and the applicant's Inservice Inspection Program (LRA AMP B.1.23). The staff evaluated the applicant's claim for this basis and finds it to be acceptable because it is consistent with the NRC recommended criteria for CASS pump casings and valve bodies in AMR item 38 of SRP-LR Table 3.1-1 and in GALL AMR item IV.C1.R-08.

The applicant also stated that AMR item 50 of SRP-LR Table 3.1-1 was not used for the evaluation of the CASS main steam line flow elements. The applicant stated that these CASS flow elements were made from CF8 CASS materials. However, the applicant clarified that loss of fracture toughness due to thermal aging is not an applicable aging effect requiring management (AERM) for these flow elements because the components were fabricated using a centrifugally cast fabrication process. The NRC's recommended basis for the program element criteria in GALL Report AMP XI.M12 and for determining when thermal aging embrittlement needs to be age-managed in CASS components is given in the NRC's evaluation on License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components." In this document, the NRC identifies that centrifugally CASS materials with a maximum molybdenum (Mo) contents of 0.5 Wt. percent are not susceptible to the phenomenon of thermal aging embrittlement. The staff noted that in GALL Report AMP XI.M12, the staff identifies that CF8 materials are low-Mo CASS materials that conform to this criteria basis. The staff also confirmed, with review of the UFSAR, that the main steam line flow elements are made from CASS CF8 materials (i.e., cast 304 stainless steel materials meeting ASTM A351 alloying requirements). Thus, based on this review, the staff evaluated the applicant's claim and finds it to be acceptable because the staff has confirmed that: (a) the main steam flow elements (restrictors) are made from centrifugally cast CF8 materials with a maximum Mo content of 0.5 Wt percent; and (b) consistent with the criteria in GALL Report AMP XI.M12 and the evaluation in License Renewal Issue No. 98-0030, loss of fracture toughness due to thermal aging embrittlement is not an AERM for centrifugally cast CF8 materials.

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" program to manage cracking due to SCC for this component group. The applicant stated that this item is not applicable because it is only applicable to PWR plants. The staff lacked 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 in-scope carbon and low alloy steel bolting exposed to air with reactor coolant leakage that may be susceptible to cracking due to SCC. The staff noted that the applicant is managing these items for loss of material and loss of preload, but not cracking due to SCC. By letter dated May 24, 2012, the staff issued RAI 3.1.1.62-1 requesting that the applicant state the basis for why cracking due to SCC is not applicable to in-scope carbon and low alloy steel closure bolting exposed to air with reactor coolant leakage (external) in the RCS.

In its response dated June 22, 2012, the applicant stated that since the GALL Report does not include any listings for high-strength steel bolting in the BWR RCS tables, the ESF Table V.E, External Surfaces of Components and Miscellaneous Bolting, was used for comparison. As a result, high-strength, low-alloy steel closure bolting is evaluated with the RV and is listed in LRA Table 3.1.2-1 and managed for cracking using the Bolting Integrity Program.

The staff finds the applicant's response acceptable because the applicant has credited the Bolting Integrity Program with managing cracking for high-strength, low-alloy steel closure bolting, the material, environment, aging effect (MEA) combination described by item 3.1.1-62 is managed through another AMR item, and there are no other in-scope stainless steel or high-strength carbon or low-alloy steel bolts exposed to air with reactor coolant leakage in the RCS susceptible to SCC, other than reactor head closure studs managed separately for aging effects by the Reactor Head Closure Studs Program. The staff's concern described in RAI 3.1.1.62-1 is resolved.

LRA Table 3.1.1, item 3.1.1-79 also addresses CASS Class 1 piping, piping component, and piping elements and CRD pressure housings exposed to a reactor coolant greater than 250 °C (greater than 482 °F) environment. The GALL Report recommends GALL Report AMP Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection" to manage loss of material for this component group, but this is only applicable to loss of material initiated solely by a corrosive or chemically related aging mechanism, such as general corrosion, pitting corrosion, or crevice corrosion. In contrast to this, UFSAR Section 5.4.4.3 identifies that the applicant selected the CF8 CASS materials for the main steam line flow elements based on their inherent resistance to loss of material by erosion-corrosion mechanism. The staff noted that in LRA Section 4.7.1, the applicant included its TLAA for managing erosion-corrosion-induced loss of material in the main steam line flow elements; however, the applicant did not include an AMR item in LRA Table 3.1.2-3 for these flow elements that credited the applicable TLAA on erosion-corrosion for managing loss of material in the main steam line flow elements by an erosion-corrosion mechanism.

By letter dated September 7, 2012, the staff issued RAI 4.7.1-2, requesting justification on why LRA Table 3.1.2-3 did not have an AMR item for these flow elements that credited the TLAA on erosion-corrosion of the main steam line flow elements for managing loss of material in the components by an erosion-corrosion mechanism.

In its response dated October 2, 2012, the applicant revised LRA Table 3.1.2-3 by adding an AMR item for loss of material due to erosion of the flow element to indicate that it is being managed through a TLAA. The staff finds this response acceptable because the LRA now provides the aging management method used by GGNS to demonstrate that the effects of aging (i.e., loss of material due to erosion) will be adequately managed for the main steam line flow elements (flow restrictors). The staff's concern described in RAI 4.7.1-2 is resolved.

3.1.2.1.2 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 due to pitting and crevice corrosion. The LRA credits the Water Chemistry Program and the One-Time Inspection Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M1, "ASME 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, and/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 LRA Table 3.1.1, item 43, for which the applicant cited generic note E, the staff noted that the One-Time Inspection Program, consistent with GALL Report AMP XI.M32, is substituted for the ASME 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 a one-time verification that pitting and crevice corrosion is not occurring or that it is occurring, but at such a slow rate that it does not affect the component's or structure's intended function during the period of expended operation. The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.41 and 3.0.3.1.32, respectively. The staff noted that the Water Chemistry Program includes controls of chemistry parameters which create an environment that is 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 Water Chemistry Program and the One-Time Inspection Program acceptable because: (1) 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, and (2) the One-Time Inspection Program will provide augmented inspections for components that are not already covered by the ISI and BWRVIP programs, but are isolated from the flow stream for extended periods and would be susceptible to the gradual accumulation or concentration of agents that promote pitting and crevice corrosion, verifying that unacceptable degradation is not occurring. The One-Time Inspection Program may also trigger additional actions that ensure the intended functions of affected components are maintained during the period of extended operation.

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 Cracking Due to Stress Corrosion Cracking and Intergranular 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 and nozzle safe ends and associated welds exposed to reactor coolant. The GALL Report recommends GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry," to ensure that cracking due to SCC and intergranular stress corrosion cracking (IGSCC) is adequately managed for this component group.

In LRA Table 3.1.2-3, the applicant cited generic note A for the AMR items that address piping, valve bodies, pump casings, and thermowells. For these AMR items, the applicant credited the BWR Stress Corrosion Cracking Program, Water Chemistry Control – BWR Program, and Inservice Inspection Program to manage cracking due to SCC and IGSCC.

In LRA Table 3.1.2-1, the applicant also cited generic note A for the AMR items that address RV nozzle safe ends and extensions, and RV nozzle thermal sleeves and thermal sleeve extensions. For these AMR items, the applicant credited the BWR Stress Corrosion Cracking Program and Water Chemistry Control – BWR Program to manage cracking due to SCC and IGSCC.

In its review, the staff noted that the inspections described in GALL Report AMP XI.M7, are mainly based on the guidance in GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) In BWR Austenitic Stainless Steel Piping," issued January 1988, which addresses inspections of piping and piping welds. Therefore, it was not clear to the staff what inspections are performed on valve bodies, pump casings, thermowells, and RV nozzle thermal sleeves and thermal sleeve extensions as part of the applicant's BWR Stress Corrosion Cracking Program.

By letter dated April 3, 2012, the staff issued RAI B.1.9-2 requesting that the applicant identify the types of inspections performed on the following components in accordance with the applicant's BWR Stress Corrosion Cracking Program: (1) stainless steel sleeves and nickel alloy thermal sleeve extensions of RV nozzles (recirculation inlet, CS inlet, RHR/LPCI nozzles), and (2) stainless steel pump casings, valve bodies, and thermowells. The staff also requested that the applicant identify the inspection methods, sample sizes, and inspection frequencies that will be applied to the inspections of these components during the period of extended operation and justify why inspection methods, sample sizes, and inspection frequencies selected are considered to be capable of detecting and managing cracking in the components during the period of extended operation.

In its response dated May 1, 2012, the applicant stated that the applicant selects components and piping for examination based on the staff-approved inspection schedule and methods described in BWRVIP-75-A. The applicant also stated that welds adjacent to specific components are inspected because welds are the susceptible areas. In addition, the applicant stated that the BWR Stress Corrosion Cracking Program specifies that these welds shall be volumetrically examined using a UT method. In its review of the applicant's response to RAI B.1.9-2, the staff finds that this portion of the applicant's response is adequate to manage cracking due to SCC and IGSCC of the pump casings, valve bodies, and thermowells and their adjacent welds, consistent with the GALL Report.

However, the staff noted that GALL Report item IV.B1.R-99 recommends the BWR Vessel Internals Program and Water Chemistry Program to manage cracking of the CS nozzle thermal sleeves. In comparison, the LRA does not include an AMR item for aging management of CS nozzle thermal sleeves based on GALL Report item IV.B1.R-99. Therefore, the staff needed further clarification as to whether the BWR Vessel Internals Program (including BWRVIP-18-A) is used to manage cracking of the CS nozzle thermal sleeves as recommended in the GALL Report. By letter dated July 23, 2012, the staff issued RAI B.1.9-2a requesting that the applicant clarify whether the BWR Vessel Internals Program is used to manage cracking of the CS nozzle thermal sleeves.

In its response dated August 15, 2012, the applicant clarified that the thermal sleeves addressed in LRA Table 3.1.2-1 are within the scope of the BWR Vessel Internals Program, consistent with the GALL Report. In its response, the applicant also revised LRA Table 3.1.2-1 to indicate that the BWR Vessel Internals Program and Water Chemistry Control - BWR Program are used to manage cracking of the thermal sleeves and thermal sleeve extensions.

In its review, the staff finds that the applicant's proposal of using the BWR Vessel Internals Program and Water Chemistry Control - BWR Program to manage cracking in these thermal sleeve components is consistent with the GALL Report and therefore, is acceptable. SER Section 3.0.3.1.10 documents the staff's evaluation regarding the applicant's aging management for the thermal sleeve components using the BWR Vessel Internals Program. The staff's concern described in RAIs B.1.9-2 and B.1.9-2a is resolved.

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).

In its review of components associated with item 3.1.1-97, the staff noted that the applicant addressed piping, valve body, pump casing, and thermowell, and cited generic note A for these components. For the AMR items associated with these components, the staff found the applicant's proposal to manage cracking due to SCC and IGSCC using the BWR Stress Corrosion Cracking Program, Water Chemistry Control – BWR Program, and Inservice Inspection Program acceptable because (1) the BWR Stress Corrosion Cracking Program includes volumetric examinations of the associated welds of these components, consistent with the GALL Report, which is adequate to manage cracking due to SCC and IGSCC, (2) the Water Chemistry Control – BWR Program includes monitoring and control of the reactor coolant water chemistry, which can mitigate environmental effects on SCC and IGSCC, and (3) the Inservice Inspection Program includes visual and volumetric examinations in accordance with the requirements of ASME Code Section XI, which are also adequate to manage cracking due to SCC and IGSCC.

In its review of components associated with LRA item 3.1.1-97, the staff noted that the applicant addressed RV nozzle thermal sleeves and thermal sleeve extensions, and cited generic note A for these components. For these AMR items associated with these components, the staff found the applicant's proposal to manage cracking due to SCC and IGSCC using the BWR Stress Corrosion Cracking Program and Water Chemistry Control – BWR Program acceptable because (1) the BWR Stress Corrosion Cracking Program includes volumetric examinations of the associated welds of these components, which is adequate to manage cracking due to SCC and IGSCC, and (2) the Water Chemistry Control – BWR Program includes monitoring and control of the reactor coolant water chemistry that can mitigate environmental effect on SCC and IGSCC.

In LRA Table 3.1.2-1, the applicant cited generic note E for the AMR item that addresses nickel alloy CRD return line cap and weld (N10). For this AMR item, the LRA credits the BWR CRD Return Line Nozzle Program and Water Chemistry Control – BWR Program to manage cracking due to SCC and IGSCC of these components.

In its review, the staff found that the applicant credited adequate AMPs to manage cracking due to SCC and IGSCC of the CRD return line cap and welds, consistent with the scopes of the BWR CRD Return Line Nozzle Program and Water Chemistry Control – BWR Program. The applicant's AMR result is consistent with GALL Report, AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle," which states that the scope of the program also includes a CRD return line nozzle cap and nozzle-to-cap welds if an applicant has cut the piping to the CRD retune line nozzle, and capped the nozzle to mitigate cracking.

The staff's evaluations of the Water Chemistry Control – BWR Program and BWR CRD Return Line Nozzle Program are documented in SER Sections 3.0.3.1.41 and 3.0.3.1.5, respectively. In its review of components associated with LRA item 3.1.1-97, the staff noted that the applicant addressed nickel alloy CRD return line cap and weld (N10), and cited generic note E for these components. For this AMR item associated with these components, the staff found the applicant's proposal to manage cracking due to SCC and IGSCC using the BWR CRD Return Line Nozzle Program and Water Chemistry Control – BWR Program acceptable because (1) the BWR CRD Return Line Nozzle Program examines the return line cap-to-safe-end weld periodically and (2) the Water Chemistry Control – BWR Program includes monitoring and control of the reactor coolant water chemistry that can mitigate environmental effect on SCC and IGSCC.

In LRA Table 3.1.2-1, the applicant also cited generic note E for the AMR items that address low alloy steel clad with stainless steel RV components (bottom head, shell closure flange, beltline shell rings and connecting welds, non-beltline shell rings, and upper head closure flange), stainless steel CRD, and stainless steel and nickel alloy heat exchanger assembly. For these AMR items, the LRA credits the Inservice Inspection Program and Water Chemistry Control – BWR Program to manage cracking of these components.

In its review, the staff noted that the Inservice Inspection Program in accordance with ASME Code, Section XI includes visual and volumetric examinations of these components, which are adequate to manage cracking due to SCC and IGSCC. Since these components are included in the scope of the Inservice Inspection Program that performs appropriate visual and volumetric examinations in accordance with ASME Code Section XI, the staff finds that the Inservice Inspection Program is adequate to manage cracking due to SCC and IGSCC of these components.

The staff's evaluations of the Water Chemistry Control – BWR Program, and Inservice Inspection Program are documented in SER Sections 3.0.3.1.41, and 3.0.3.1.22, respectively. In its review of components associated with LRA item 3.1.1-97, the staff noted that the applicant addressed low alloy steel clad with stainless steel RV components, stainless steel CRD, and stainless steel and nickel alloy heat exchanger assembly. For the AMR items associated with these components, the staff found the applicant's proposal to manage cracking due to SCC and IGSCC using the Water Chemistry Control – BWR Program and Inservice Inspection Program acceptable because (1) the Water Chemistry Control – BWR Program includes monitoring and control of the reactor coolant water chemistry, which can mitigate environmental effect on SCC and IGACC and (2) the Inservice Inspection Program includes visual, surface, and volumetric examinations of these components in accordance with the requirements of ASME Code Section XI, which are adequate to manage cracking due to SCC and IGSCC.

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).

3.1.2.1.4 Cracking Due to Stress Corrosion Cracking, Intergranular Stress Corrosion Cracking, and Cyclic Loading

LRA Table 3.1.1, item 3.1.1-98 addresses stainless steel or nickel alloy penetrations of the RV, which will be managed for cracking due to SCC, IGSCC, and cyclic loading. For the AMR items that cite generic note E, the LRA credits the Water Chemistry Control – BWR Program and BWR Vessel Internals Program to manage the aging effect for the RV penetrations. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," and AMP XI.M8, "BWR Penetrations," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M2 recommends monitoring and controlling of the concentrations of corrosive impurities listed in the EPRI water chemistry guidelines to mitigate the environmental effects on cracking. GALL Report AMP XI.M8 recommends the inspections in accordance with BWRVIP-49-A, BWRVIP-47-A, BWRVIP-27-A, and ASME Code Section XI, Table IWB-2500-1.

In its review, the staff noted that LRA Table 3.1.2-1 addresses applicant's AMR results for the RV, including RV nozzles and penetrations. LRA Table 3.1.2-1 indicates that the BWR Vessel Internals Program and Water Chemistry Control – BWR Program manage cracking due to SCC, IGSCC, and cyclic loading of the CRD housing penetrations and incore housing penetrations in LRA items 3.1.1-102 and 3.1.1-98, respectively.

In contrast, GALL Report item IV.A1.RP-369 and the program scope of the BWR Penetrations Program recommend that the BWR Penetrations Program and Water Chemistry Program be used to manage cracking of these RV penetrations. Therefore, the applicant's AMR results for cracking of the CRD housing and in-core housing penetrations (which are part of the RCPB) are not consistent with GALL Report item IV.A1.RP-369 and the scope of the BWR Penetrations Program.

By letter dated April 1, 2012, the staff issued RAI B.1.8-4 requesting that the applicant justify why cracking due to SCC, IGSCC and cyclic loading of the CRD housing penetrations and incore housing penetrations is managed by the BWR Vessel Internals Program and Water Chemistry Control – BWR Program, inconsistent with GALL Report item IV.A1.RP-369 and the scope of GALL Report AMP XI.M8, "BWR Penetrations."

In its response dated August 15, 2012, the applicant stated inspection guidance for the CRD housings and in-core housings is provided in BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," and for the purposes of comparisons to the GALL Report, the BWR Penetrations Program described in GALL Report AMP XI.M8, which references BWRVIP-47-A, better represents the AMP requirements. In its response, the applicant also provided revisions to LRA Table 3.1.2-1 and LRA Table 3.1.1, item 3.1.1-98, in order to identify that the BWR Penetrations and Water Chemistry Control – BWR Programs manage cracking of the CRD housing penetrations and incore housing penetrations, consistent with the GALL Report.

The staff finds the applicant's response acceptable because the applicant's revisions to the LRA are consistent with the GALL Report that recommends the BWR Penetration Program in conjunction with the Water Chemistry Program to manage cracking of the CRD and incore housing penetrations that are part of the RCPB. The staff also finds that the BWR Penetrations Program includes the examinations specified in BWRVIP-47-A and ASME Code Section XI, which are adequate to detect and manage cracking of these RV penetrations. The staff's concern described in RAI B.1.8-4 is resolved.

The staff's evaluations of the applicant's Water Chemistry Control – BWR Program and BWR Penetrations Program are documented in SER Sections 3.0.3.1.41 and 3.0.3.1.7, respectively. In its review of the components associated with item 3.1.1-98, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry Control – BWR Program and BWR Penetrations Program acceptable because the applicant's Water Chemistry Control – BWR Program manages the aging of the components through monitoring and control of water chemistry in accordance with the EPRI water chemistry guidelines, and the applicant's BWR Penetrations Program manages the aging of the components through the examinations in accordance with applicable industry standards and staff-approved BWRVIP documents, consistent with the GALL Report, which are adequate to manage the effects of aging for these components.

The staff concludes that for LRA item 3.1.1-98, 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 Cracking Due to Stress Corrosion Cracking, Intergranular Stress Corrosion Cracking, and Irradiation Assisted Stress Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-103, addresses stainless steel in-core dry tubes exposed to reactor coolant and neutron flux which are being managed for cracking due to SCC, IGSCC, and IASCC. The LRA credits the Water Chemistry Program and the Inservice Inspection Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M9, "BWR Vessel Internals," 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.M9 recommends using periodic visual, surface, and/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 LRA Table 3.1.1, item 103, for which the applicant cited generic note E, the staff noted that the applicant's Inservice Inspection Program, consistent with the GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program," is substituted for the BWR Vessels Internals Program. The staff's evaluation of the applicant's Water Chemistry and Inservice Inspection Programs are documented in SER Sections 3.0.3.1.41 and 3.0.3.1.32, respectively.

In its review of components associated with LRA Table 3.1.1, item 103, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and the Inservice Inspection Program acceptable because (a) the applicant's use of the Water Chemistry Program creates an environment that is not conducive for cracking to occur and is consistent with the recommendations of the GALL Report, and (b) the visual inspections associated with the Inservice Inspection Program is capable of detecting cracking during the period of extended operation.

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 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed are not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed are not applicable are not applicable to GGNS.

As discussed in SER Section 3.1.2.1, 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 RV, internals, and RCS components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC)
- crack growth due to cyclic loading
- cracking due to SCC
- cracking due to cyclic loading
- loss of material due to erosion
- cracking due to SCC and irradiation-assisted SCC (IASCC)

- loss of fracture toughness due to neutron irradiation embrittlement; change in dimension due to void swelling; loss of preload due to stress relaxation; or loss of material due to wear
- cracking due to primary water SCC (PWSCC)
- cracking due to fatigue
- cracking due to SCC and fatigue
- loss of material due to 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 RPV, RVI, 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 stud 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 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 RV 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 pressurized water reactor 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 consistent with 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 due to general, pitting, and crevice corrosion in steel PWR steam generator components exposed to secondary feedwater and steam. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim 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 due to general, pitting, and crevice corrosion in steel PWR steam generator components exposed to secondary feedwater and steam. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim 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 neutron irradiation embrittlement is a TLAA 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 is documented in SER Section 4.2.

(2) LRA Section 3.1.2.2.3 refers to LRA Table 3.1.1, item 14 and addresses RPV steel (with or without cladding) RV beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux, which are being managed for loss of fracture toughness due to neutron irradiation embrittlement by the applicant's Reactor Vessel Surveillance Program.

    The SRP-LR states that the applicant must implement a reactor surveillance program that follows the requirements of 10 CFR Part 50, Appendix H, by incorporating plant-specific factors such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In addition, the plant-specific program must provide for untested capsules to be maintained in a manner such that they could be re-inserted into the vessel in the future if the need arises. This program monitors changes in the fracture toughness properties of ferritic materials in the reactor pressure vessel (RPV) beltline region. As described in Appendix B, the Reactor Vessel Surveillance Program is consistent with the program described in NUREG-1801, Section XI.M31, Reactor Vessel Surveillance, including recommendations for maintaining untested capsules in storage for future reinsertion.

The staff's evaluation of the applicant's Reactor Vessel Surveillance Program noted the applicant's program consists of periodic testing of metallurgical surveillance samples to monitor the progress of neutron embrittlement of the RPV as a function of neutron fluence that is capable of identifying, evaluating, and managing the effects of loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding of the RV.

The applicant addressed the further evaluation requirement by stating that the Reactor Vessel Surveillance Program manages reduction in fracture toughness due to neutron embrittlement of RV beltline materials, and relies on the BWRVIP ISP, of which GGNS is a participant, and satisfies the requirements of 10 CFR Part 50, Appendix H.

The Reactor Vessel Surveillance Program will adequately identify, evaluate, and manage the effects of loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding of the RV to ensure there is no loss of intended function during the period of extended operation.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.3, item 14 criteria. For the item that applies to LRA Section 3.1.2.2.3, Table 3.1.1, item 14, the staff determines 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) 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 and is not applicable to GGNS. 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 item 3.1.1-16 addresses the nickel alloy vessel flange leak detection (VFLD) nozzle which will be managed for cracking due to SCC and IGSCC by the Water Chemistry Control – BWR Program and ISI Program. The applicant further states that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control – BWR Program. The criteria in SRP-LR Section 3.1.2.2.4 item 1 state that cracking due to SCC and IGSCC could occur in stainless steel and nickel alloy BWR top head enclosure vessel flange leak detection lines. The GALL Report recommends that a plant-specific AMP be evaluated because

existing programs may not be capable of mitigating or detecting cracking due to SCC and IGSCC.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that the VFLD nozzle is nickel alloy, and has the potential for cracking due to SCC and IGSCC. The applicant further states the leak detection line downstream of the nozzle is ASME Class 2, and the portion of this line that is wetted during refueling is carbon steel. The applicant cites LRA Table 3.1.1, item 3.1.1-16, which credits the Water Chemistry Control – BWR Program and ISI Programs. The applicant also describes, in LRA Appendix C, the GGNS response to BWRVIP applicant action items. BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” states concerns of leakage around the RV seal rings that could accumulate in the VFLD lines that could cause cracking in the line. The applicant stated in its response to the action item that the VFLD line is managed by the Water Chemistry Control – BWR Program, which will be confirmed by the One-Time Inspection Program.

The staff’s evaluation of the applicant’s Water Chemistry Control – BWR Program is documented in SER Section 3.0.3.1.41. The staff noted that the applicant’s program manages loss of material, cracking, and fouling in components exposed to a treated water environment through monitoring and control of water chemistry, using EPRI water chemistry guidelines. The staff further noted that enhancements based on industry experience and guidelines, BWR cycle design, and BWR metallurgy were implemented to optimize corrosion control for the RV, primary system components, and balance of plant components and reduce IGSCC. The staff noted that these enhancements included the addition of an advanced resin cleaning system and management of condensate temperatures in cold weather months.

The staff’s evaluation of the applicant’s ISI Program is documented in SER Section 3.0.3.1.22. The staff noted that the applicant’s program includes the requirements of ASME Code Section XI, Subsections IWB, IWC, and IWD, which manages aging effects for ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments and pressure-retaining bolting using volumetric, surface, or visual examination.

In its review of components associated with item 3.1.1-16, the staff finds that the applicant has met the further evaluation criteria, and the applicant’s proposal to manage aging using the Water Chemistry Control – BWR Program and ISI Program is acceptable because the applicant’s use of programs capable of mitigating and detecting SCC and IGSCC, the aging effect, and mechanism is consistent with the recommendations of the GALL Report and SRP-LR Section 3.1.2.2.4, item 1.

The staff determines that the applicant’s programs meet SRP-LR Section 3.1.2.2.4, item 1 criteria. For those AMR 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 applicant’s UFSAR and confirmed that the design of the applicant’s unit does not include an isolation condenser; therefore, the staff finds the applicant’s review result acceptable.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5, associated with LRA Table 3.1.1, item 3.1.1-18, addresses intergranular separations (underclad cracks) in welds used to join cladding to RPV shell or nozzle forgings made from SA-508 Class 2 alloy steel materials and are exposed to the reactor coolant environment. The LRA states that this item is not applicable to the LRA because the issue is only applicable to SA-508 Class 2 RPV forging components in PWR designs.

SRP-LR Section 3.1.2.2.5 identifies that crack growth due to cyclic loading could occur in RPV low alloy steel forging components that have a coarse-grained material structure and that were clad with austenitic stainless steel using a high-heat-input welding process. The SRP-LR states that growth of intergranular separations (underclad cracks) in the heat-affected zone of RPV clad-to-forging welds may need to be identified as a TLAA for the period of extended operation.

The staff sought additional information from the applicant to confirm that the LRA would not need to include an RPV underclad cracking TLAA. By letter dated June 5, 2012, the staff issued RAI 4.1-1, requesting in part (a) of the RAI, that the applicant identify the RPV forging components that were ordered and fabricated to SA-5O8, Class 2 specifications and whose design included an associated welded cladding. In RAI 4.1-1, part (b), the staff asked the applicant to clarify the regulatory process used in the CLB to address underclad cracking in the RPV cladding-to-forging welds. In RAI 4.1-1, part (c), the staff also asked the applicant to justify why the assessment of RPV underclad cracking would not need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

The applicant responded to RAI 4.1-1 by letter dated July 3, 2012. In its response to RAI 4.1-1, part (a), the applicant stated the only RPV components that were made from SA-508, Class 2 low alloy steel forging materials are the RPV lower flange component that is welded to the RPV shell and the RPV upper flange component that is welded to the RPV upper head. In its response to RAI 4.1-1, part (b), the applicant stated that the UFSAR Section 5.3.1.6.4 identifies that its RPV design specifications required all low alloy steel components in the RPV to be fabricated from materials and welding methods that resulted in fine-grain microstructures and that based on this, the phenomenon of underclad cracking is not a concern for RPV flange components that were fabricated from SA-508 Class 2 forging materials. The applicant also stated that this is the only reference to RPV underclad cracking that is incorporated into the CLB. In its response to RAI 4.1-1, part (c), the applicant stated that the CLB does not include any time-dependent RPV underclad cracking analysis and that based on this fact, that there is not any RPV underclad cracking analysis to identify for the LRA.

The staff finds the applicant's response acceptable because the UFSAR Section 5.3.1.6.4 indicates that all low alloy steel components in the RPV were fabricated from materials and welding methods that resulted in fine-grain microstructures; RPV components were made from SA-508, Class 2 low alloy steel forging materials; and its CLB does not include any time-dependent RPV underclad cracking analysis. The staff's concern described in RAI 4.1-1 is resolved.

The staff also confirmed that the UFSAR verifies that the RPV upper and lower flange component forgings were fabricated using fine-grain material fabrication processes. Therefore, based on this review, the staff finds that the applicant presented a valid basis for concluding that the management of underclad is not applicable to the applicant and that the LRA does not need to include a RPV underclad cracking TLAA because the staff has confirmed that: (a) the operating experience with underclad cracking is relevant to SA-508, Class 2 RPV forging components in PWR designed facilities; (b) that the RPV upper and lower flange forging components were fabricated to fine-grain material fabrication processes; and (c) the CLB does not include a RPV underclad cracking analysis for these RPV flange components.

3.1.2.2.6 Cracking Due to 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 due to SCC in PWR stainless steel RV flange leak detection lines and bottom-mounted instrument guide tubes exposed to reactor coolant. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff 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 due to SCC in Class 1 PWR CASS RCS piping, piping components, and piping elements. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.7 Cracking Due to 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 due to 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 applicant's 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.

3.1.2.2.8 Loss of Material Due to 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 due to erosion in PWR steam generator FW impingement plates and supports exposed to secondary FW. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.9 Cracking Due to 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 due to SCC and IASCC could occur in inaccessible locations for stainless steel and nickel-alloy primary and expansion PWR RVI components. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.10 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement, Change in Dimension Due to Void Swelling, Loss of Preload Due to Stress Relaxation, or Loss of Material Due to 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 due to neutron irradiation embrittlement, change in dimension due to void swelling, loss of preload due to stress relaxation, or loss of material due to wear that could occur in inaccessible locations for stainless steel and nickel-alloy primary and expansion PWR RVI components. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.11 Cracking Due to 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 due to 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 SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff 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 due to PWSCC that could occur in steam generator nickel alloy tube-to-tube sheet welds exposed to reactor coolant. The applicant stated that this SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.12 Cracking Due to Fatigue

LRA Section 3.1.2.2.12, which is associated with LRA Table 3.1.1, item 3.1.1-26, addresses cracking due to 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 SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.13 Cracking Due to 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 due to 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 SRP-LR item is not applicable to GGNS because it is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and; therefore, the staff finds the applicant's claim acceptable.

3.1.2.2.14 Loss of Material Due to Wear

LRA Section 3.1.2.2.14, associated with LRA Table 3.1.1, item 3.1.1-28, addresses loss of material due to wear in nickel alloy control rod guide tube assemblies, guide tube support pins, and Zircaloy-4 incore 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 3.1.2-4, 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 3.1.2-4, 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.

3.1.2.3.1 Reactor Vessel - 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 RV component groups.

In LRA Section 3.1.2.1.1, which is associated with LRA Table 3.1.2-1, the applicant stated that carbon and low-alloy steel RV external attachments, support skirt, and stabilizer attachment brackets exposed to indoor air will be managed for loss of material by the applicant's ISI program. The AMR item cites generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination. 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, the staff finds that the applicant has identified all credible aging effects for these component, material, and environment combinations.

The staff's evaluation of the ISI program is documented in SER Section 3.0.3.1.22. The staff noted that the ISI program manages loss of material for the RV external attachments, support skirt, and stabilizer attachment brackets using visual and volumetric inspections in accordance with ASME Code Section XI, Subsection IWA. The staff finds that the applicant's proposed program to manage loss of material for carbon steel and low-alloy steel exposed to indoor air acceptable because the applicant will use inspection techniques that are in accordance with ASME Code Section XI, Subsection IWA, which are acceptable for detection of loss of material.

In LRA Table 3.1.2-1, the applicant stated that the carbon steel and low alloy steel components including nozzles, nozzle safe ends and extensions, nozzle flanges, RV head, and flange exposed to indoor air does not have any aging effects that require management. The related AMR items cite generic note G, indicating this environment is not in the GALL Report for the aging effects of this component and material combination. In addition, the associated plant-specific note 102 states that high component surface temperature precludes moisture accumulation that could result in corrosion.

In its review, the staff found that essentially identical material and environment combinations were found in the GALL Report, albeit not in the RCS. The staff noted that the applicant's basis for stating that no aging management is necessary was that the temperature of the components under consideration was above the dew point. However, the staff also noted that, during refueling outages, the components could be at ambient temperatures for prolonged periods of time, negating the plant-specific note. By letter dated June 20, 2012, the staff issued RAI 3.1.2.1-1 requesting that the applicant provide technical basis to justify why aging management is not necessary given that, during normal plant events such as refueling outages, these components will be at or near ambient temperatures. In its response dated July 19, 2012, the applicant stated that the subject components are typically at or near ambient temperatures and are rarely below ambient temperatures during shutdown conditions, such as refueling outages. It stated that "these conditions are comparatively brief," and that "any minor moisture accumulated during shutdown is quickly evaporated during startup." The applicant also indicated that its "operating experience has shown that these components are not subject to loss of material due to corrosion."

Based on its review, the staff finds the applicant's response to RAI 3.1.2.1-1 acceptable, because the applicant provided information indicating that water condensation seldom occurs on the exterior surfaces of the referenced components. In addition, the applicant's plant-specific operating experience demonstrated that these components are not subject to loss of materials due to corrosion. Therefore, the staff's concerns described in RAI 3.1.2.1-1 are resolved.

Based on its review, the staff finds the applicant has appropriately identified that the above-mentioned components are not subject to AERM because component temperatures are above the dew point and water condensation seldom occurs on the exterior surfaces of the components. Loss of material due to corrosion is not expected with these conditions.

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 Vessel Internals - Summary of Aging Management Review – LRA Table 3.1.2-2

The staff reviewed LRA Table 3.1.2-1, which summarizes the results of AMR evaluations for the RVI 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.

3.1.2.3.3 Reactor Coolant Pressure Boundary - 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 RCPB component groups.

Carbon Steel Piping and Piping Components Exposed to Air-Indoor (External). In LRA Table 3.1.2-3, the applicant stated that carbon steel piping, flow elements, thermal sleeves, and valve bodies exposed to air-indoor (external) have no aging effects and no AMP is proposed. The AMR items cite generic note G and plant-specific note 102, which states that the high component surface temperature precludes moisture accumulation that could result in corrosion. The staff's concern with the basis for this conclusion for outages, where component surfaces temperatures are lower, is documented in SER Section 3.1.2.3.3.

The staff reviewed the associated items in the LRA to confirm that there are no credible aging effects for this component, material and environmental combination. The staff noted that the ASM Handbook, Volume 13A, 2003, chapter on "Atmospheric Corrosion," states that the atmospheric corrosion reaction will not occur without the presence of an electrolyte. The staff also noted that moisture accumulation is not expected to occur on components with temperatures above the atmospheric dew point. The staff further noted that GALL Report item VII.J.AP-4 states that steel piping, piping components, and piping elements exposed to dry air have no aging effects. The staff finds the applicant's proposal acceptable because high component surface temperatures prevent the accumulation of the moisture (i.e., electrolyte) necessary for aging to occur.

Carbon Steel Piping and Valve Bodies Less Than 4-inch NPS Exposed to Air–Indoor (External). In LRA Table 3.1.2-3, the applicant stated that for carbon steel piping less than 4 inches NPS exposed to indoor air on their external surfaces, there is no aging effect and no AMP is proposed. The AMR items cite generic note G, which states that the environment for this component and material is not found in the GALL Report. The AMR items also cite a plant-specific note that states that high component surface temperature precludes moisture accumulation that could result in corrosion.

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.

In its review, the staff noted that the applicant's basis for stating that no aging effect was present was that the external surface temperature of the components was above the dew point. The staff also noted that the GALL Report defines indoor air as an environment in which condensation is only expected on rare occasions. The staff further noted that this combination of environment and material is present in the GALL Report, albeit not in the RCS, and that the management of the aging effect, loss of material, is recommended.

By letter dated June 20, 2012, the staff issued RAI 3.1.2.1-1, requesting that the applicant justify why aging management is not required for these components given that during normal plant events (e.g., refueling), the components under consideration will be at or near ambient temperature and may be subject to condensation.

By letter dated July 19, 2012, the applicant responded to RAI 3.1.2.1-1, which stated that these components are at or near (but seldom, if ever, below) ambient temperatures during shutdown conditions, such as refueling outages. The applicant stated that these conditions are comparatively brief. The applicant stated that the dew point inside containment during outages is typically below the ambient temperature. The applicant stated that actual condensation on RCS piping is not a concern because of these conditions. The applicant further stated that any minor moisture that accumulated during shutdown is quickly evaporated during startup; these components operate at high temperatures (greater than 212 °F) during normal operation. The applicant also stated that operating experience has shown that these components are not subject to loss of material due to corrosion.

Based on its review, the staff finds the applicant has appropriately identified that the above-mentioned components are not subject to AERM because component temperatures are above the dewpoint and the duration of time when the component temperature is near the dewpoint is too short to allow significant corrosion to occur even if condensation does occur. Loss of material due to corrosion is not expected with these conditions.

<u>Loss of Material Due to Erosion in Main Steam Line Flow Elements</u>. By letter dated October 2, 2012, the applicant amended LRA Table 3.1.2-3 to include a new AMR item on loss of material due to erosion in the plant's main steam line flow elements (flow restrictors) that are made from cast austenitic stainless steel (CASS). In this AMR item, the applicant stated that loss of material due to erosion in main steam flow elements that are exposed to reactor steam environment will be managed for loss of material due to erosion by the time-limited aging analysis for this aging. The AMR item cites generic note H.

The staff reviewed the associated item in the response letter that amended 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 loss of material due to erosion is a specific aging effect and mechanism that is applicable to this component, material and environment combination. The staff verified that the applicant included the applicable TLAA for managing loss of material due to erosion in the main steam line flow elements in LRA Section 4.7.1 and that this serves as an acceptable basis for complying with the aging management requirement in 10 CFR 54.21(a)(3). Based on this review, the staff finds that the applicant has included an applicable AMR item for managing loss of material due to erosion in the CASS main steam line flow elements. The staff's evaluation of the applicant's TLAA for the main steam line flow elements is documented in SER Section 4.7.1.

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).

3.1.2.3.4 Miscellaneous RCS systems in scope for 10 CFR 54.4(a)(2) - Summary of Aging Management Review – LRA Table 3.1.2-4

The staff reviewed LRA Table 3.1.2-4, which summarizes the results of AMR evaluations for the miscellaneous RCS systems in scope for 10 CFR 54.4(a)(2) 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.

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the RV, RVI, 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 section of the SER documents the staff's review of the applicant's AMR results for the engineered safety features systems components and component groups of:

- RHR
- low pressure core spray
- high pressure core spray (HPCS)
- RCIC
- pressure relief
- standby gas treatment
- containment penetrations
- miscellaneous ESF systems in scope for 10 CFR 54.4(a)(2)

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the engineered safety features (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 which 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/ 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 due to fatigue	Fatigue is a time-limited aging analysis (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/ 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 due to cladding breach	A plant-specific AMP is to be evaluated Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes	Not applicable	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 due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottom because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering.	Yes	Not applicable	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 due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Not applicable	Not applicable to GGNS (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 due to erosion	A plant-specific AMP is to be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging. See LER 50-275/94-023 for evidence of erosion.	Yes	Not applicable	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 due to general corrosion; fouling that leads to corrosion	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.2.5)
Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor (3.2.1-7)	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.2.6)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Not applicable	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 due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Not applicable	Not applicable to BWRs (see SER Section 3.2.1.1)
Cast austenitic stainless steel 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 due to thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Not applicable	Not applicable to GGNS (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 due to 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 due to cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel; stainless steel volting, closure bolting exposed to air – outdoor (external); air – indoor, uncontrolled (external) (3.2.1-13)	Loss of material due to 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 due to general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	See SER Section 3.2.2.1.1

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
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 due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR, One-Time Inspection, and Bolting Integrity, Periodic Surveillance and Preventive Maintenance	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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR, One-Time Inspection, and Bolting Integrity, Periodic Surveillance and Preventive Maintenance	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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR and One-Time Inspection	Consistent with the GALL Report
Stainless steel heat exchanger tubes exposed to treated water (3.2.1-19)	Reduction of heat transfer due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	Not applicable	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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Not applicable	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 due to general, pitting, crevice, and microbiologically - influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-24)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	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 due to pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report
Stainless steel heat exchanger tubes exposed to raw water (3.2.1-26)	Reduction of heat transfer due to fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report
Stainless steel, steel heat exchanger tubes exposed to raw water (3.2.1-27)	Reduction of heat transfer due to fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to GGNS (See SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to stress corrosion cracking	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – BWR and Inservice Inspection	Consistent with the GALL Report (see SER Section 3.2.2.1.4)
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-29)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report
Steel heat exchanger components exposed to closed-cycle cooling water (3.2.1-30)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – Closed Treated Water System	Not applicable to GGNS (see SER Section 3.2.2.1.5)
Copper-alloy Heat exchanger components, Piping, piping components, and piping elements exposed to Closed-cycle cooling water (3.2.1-32)	Loss of material due to pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – Closed Treated Water System	Consistent with the GALL Report
Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water (3.2.1-33)	Reduction of heat transfer due to fouling	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to GGNS (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 due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-36)	Loss of material due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	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 due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to GGNS (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 due to elastomer degradation	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	External Surfaces Monitoring	Consistent with the GALL Report
Steel containment isolation piping and components (external surfaces) exposed to condensation (external) (3.2.1-39)	Loss of material due to general corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	External Surfaces Monitoring	Consistent with the GALL Report
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 due to general corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	External Surfaces Monitoring	Consistent with the GALL Report
Steel external surfaces exposed to air – outdoor (external) (3.2.1-41)	Loss of material due to general corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to elastomer degradation	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel piping and components (internal surfaces), ducting and components (internal surfaces) exposed to air – indoor, uncontrolled (internal) (3.2.1-44)	Loss of material due to general corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel encapsulation components exposed to air – indoor, uncontrolled (internal) (3.2.1-45)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	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 due to general, pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)
Steel encapsulation components exposed to air with borated water leakage (internal) (3.2.1-47)	Loss of material due to general, pitting, crevice, and boric acid corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	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 due to pitting and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	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 due to general, pitting, and crevice corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Copper alloy, stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-50)	Loss of material due to pitting and crevice corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Oil Analysis and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil (3.2.1-51)	Reduction of heat transfer due to fouling	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	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 due to general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Not applicable	Not applicable to GGNS (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 due to general (steel only), pitting and crevice corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Not applicable	Not applicable to GGNS (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 due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M7, “BWR Stress Corrosion Cracking,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)
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 operating experience indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 air – indoor, uncontrolled (internal/external) (3.2.1-56)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)
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	Not applicable	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	Not applicable	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	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)
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	Not applicable	Consistent with the GALL Report (see SER Section 3.2.2.1.1)
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	Not applicable	Not applicable to GGNS (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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	Not applicable	Not applicable to GGNS (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	Not applicable	Consistent with the GALL Report (see SER Section 3.2.2.1.6)
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	Not applicable	Not applicable to GGNS (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
- Compressed Air Monitoring
- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Internal Surfaces in Miscellaneous Piping and Ducting Components
- Oil Analysis
- One-Time Inspection
- Periodic Surveillance and Preventive Maintenance
- Selective Leaching

- Service Water Integrity
- Water Chemistry Control – BWR
- Water Chemistry Control – Closed Treated Water Systems

LRA Tables 3.2.2-1 through 3.2.2-8 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.

3.2.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.2.1, items 3.2.1-8, 3.2.1-9, 3.2.1-20 through 3.2.1-22, 3.2.1-24, 3.2.1-35, 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 that these items are not applicable to GGNS.

For LRA Table 3.2.1, items 3.2.1-10, 3.2.1-30, 3.2.1-33, 3.2.1-34, 3.2.1-37, 3.2.1-41, 3.2.1-42, 3.2.1-46, 3.2.1-52, 3.2.1-53, 3.2.1-55, 3.2.1-56, 3.2.1-61, and 3.2.1-62, the applicant claimed that the corresponding items in the GALL Report are 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.

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" program to manage loss of material due to general corrosion for this component group. The applicant stated that this item is not applicable because steam or water leakage is not considered a separate aspect of the indoor air environment. The staff evaluated the applicant's claim and found it acceptable because (a) all ESF system bolting exposed to air is being managed for loss of material by the Bolting Integrity Program using item 3.2.1-13, (b) the program conducts periodic visual inspections capable of detecting loss of material due to general corrosion in bolting, and (c) use of this program is consistent with the GALL Report.

LRA Table 3.2.1, item 3.2.1-27, addresses stainless steel and steel heat exchanger components exposed to raw water that are being managed for reduction of heat transfer due to 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 this item was not used because there are no steel heat exchanger tubes in ESF systems exposed to raw water, and the stainless steel heat exchanger tubes in ESF systems are being managed for reduction of heat transfer through Table 3.2.1, item 3.2.1-26. The staff finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-53.5, addresses steel and stainless steel underground piping, piping components, and piping elements exposed to uncontrolled indoor air or condensation (external). The GALL Report recommends GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," to manage loss of material due to general (steel only), pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because, "[t]his item was not used. There are no underground ESF system components in the scope of license renewal." The staff evaluated the applicant's claim and lacked sufficient information to find it acceptable because an enhancement to LRA Section B.1.18, External Surfaces Monitoring Program, states that instructions will be provided for inspecting all underground components within the scope of this program. Based on the staff's review during the AMP audit, the RHR pump suction barrels and HPCS pump suction barrels are two of the underground piping components associated with this enhancement. By letter dated April 16, 2012, the staff issued RAI B.1.5-1 requesting that the applicant provide a list of all underground in-scope components, state which AMP will be used to manage the aging of these underground in-scope components, and if a program other than the Buried Piping and Tanks Inspection Program will be used to age manage any of the underground components, state if any recommendations contained in AMP XI.M41 of the GALL Report will not be met and justify not meeting the recommendations. The applicant's response and staff evaluation of this RAI is documented in SER Section 3.0.3.1.4. The staff's concern described in RAI B.1.5-1 is resolved and the staff finds the applicant's use of item 3.2.1-40 to manage the steel RHR suction barrel HPCS suction barrel acceptable.

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). The GALL Report recommends GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry," to manage cracking due to SCC and IGSCC for this component group. The applicant stated that this item is not used because stainless steel components of the ESF systems subject to evaluation under the BWR Stress Corrosion Cracking Program were reviewed as part of the RCPB (LRA Table 3.1.2-3).

In its review, the staff needed to further clarify whether the scope of the applicant's BWR Stress Corrosion Cracking Program includes relevant piping and piping welds regardless of ASME Code classification, consistent with GALL Report AMP XI.M7. The staff noted that LRA Section B.1.9 for the BWR Stress Corrosion Cracking Program includes the RCPB components in the program scope, but does not clearly address whether the scope of the program includes non-Class 1 piping and associated welds.

By letter dated April 3, 2012, the staff issued RAI B.1.9-1 requesting that the applicant clarify whether the scope of the BWR Stress Corrosion Cracking Program includes non-Class 1 piping and piping welds made of austenitic stainless steel and nickel alloy materials. The staff also requested that if not included, the applicant justify why non-Class 1 piping and piping welds are excluded from the scope of the BWR Stress Corrosion Cracking Program.

In its response dated May 1, 2012, the applicant clarified that the BWR Stress Corrosion Cracking Program applies to relevant BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of code classification, consistent with the GALL Report as described in LRA Section B.1.9. The applicant also clarified that non-Class 1 piping and piping welds were not excluded from the program. The applicant further clarified that at GGNS, all components included in the scope of this program are part of the RCPB and were subject to an AMR. In addition, the applicant indicated that the results of the AMR of these RCPB components are documented in LRA Tables 3.1.2-1 and 3.1.2-3.

In its review of the applicant's response to RAI B.1.9-1, the staff noted that the applicant clarified that its BWR Stress Corrosion Cracking Program applies to the relevant BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of code classification, consistent with the GALL Report. However, LRA item 3.2.1-54 indicates that the components in the ESF systems, subject to the BWR Stress Corrosion Cracking Program, were reviewed as part of the RCPB. Therefore, the staff needed justification as to why the components associated with LRA item 3.2.1-54 were reviewed as part of the RCPB, which consists of Class 1 components as discussed in LRA Section 2.3.1.2.

By letter dated July 23, 2012, the staff issued RAI B.1.9-1a requesting that the applicant justify why LRA Sections B.1.9 and A.1.9 indicate that the BWR Stress Corrosion Cracking Program manages only aging of the RCPB in contrast with the program scope recommended in the GALL Report that includes relevant piping and piping welds regardless of code classification. The staff also requested that the applicant clarify why LRA item 3.2.1-54 indicates that the components in the ESF systems, subject to the BWR Stress Corrosion Cracking Program, were reviewed as part of the RCPB, rather than against the relevant piping and piping welds (regardless of code classification) recommended in GALL Report AMP XI.M7.

In its response dated August 15, 2012, the applicant stated that there are no piping components or piping welds made of austenitic stainless steel or nickel alloy that are 4 inches or larger in nominal diameter and contain reactor coolant at a temperature above 93°C (200°F) during power operation in the non-Class 1 portions of the ESF system. The applicant further provided revisions to LRA item 3.2.1-54 to clarify that there are no components outside the reactor coolant pressure boundary subject to the BWR Stress Corrosion Cracking Program requirements. The staff finds that the applicant's response acceptable because the applicant confirmed that the ESF system has no non-Class 1 components that should be included in the scope of the applicant's BWR Stress Corrosion Cracking Program. The staff's concerns described in RAIs B1.9-1 and B.1.9-1a is resolved.

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).

LRA Table 3.2.1, item 3.2.1-59 addresses galvanized steel ducting, piping, and components exposed to air-indoor, controlled. The GALL Report recommends that there are no aging effects, aging mechanisms, or AMPs. The applicant stated that this item is not applicable because galvanized steel components were evaluated as steel. The staff noted that the applicant also evaluated all air-indoor environments as uncontrolled in the ESF system, rather than controlled. The staff also noted that the LRA includes AMR evaluations for steel ducting and piping components exposed to plant indoor air that references LRA Table 3.2.1, items 3.2.1-40 (external environments) and 3.2.1-44 (internal environments) and credit the External Surfaces Monitoring and Internal Surfaces in Miscellaneous Piping and Ducting Components Programs, respectively, to manage loss of material due to general corrosion in ESF systems. The staff evaluated the applicant's claim and finds it acceptable because the applicant chose to evaluate the subject components as being constructed of a more susceptible material and exposed to a more aggressive environment, referencing appropriate alternative Table 1 items and managing aging consistent with GALL Report recommendations for those Table 1 items.

LRA Table 3.2.1, item 3.2.1-60 addresses glass piping elements exposed to uncontrolled indoor air, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water, and outdoor air. The applicant stated that it is consistent with the GALL Report for glass components exposed to indoor air and lube oil, but that for other environments there are no glass components within the ESF systems that are within the scope of license renewal. SRP-LR Table 3.2-1, item 3.2.1-60 states that there are no aging effects or aging mechanisms, and that no AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-64 addresses steel piping, piping components, and piping elements exposed to air – indoor, controlled (external) and gas and states that there are no aging effects, aging mechanisms or AMPs. SRP-LR item 3.2.1-64 recommends that there is no aging effect or aging mechanism, and that no AMP is recommended for this component group exposed to this environment; therefore, the staff finds the applicant's determination acceptable.

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

LRA Table 3.2.1, item 3.2.1-16 addresses steel containment isolation piping and components (internal surfaces), piping, piping components, and piping elements exposed to treated water, which will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs to manage the aging effect for steel containment isolation and other ESF system components. 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. GALL Report AMPs XI.M2 and XI.M32 recommend using water chemistry controls and a one-time visual or volumetric inspection to manage aging.

The staff's evaluations of the applicant's Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs are documented in SER Sections 3.0.3.1.41, 3.0.3.1.32, and 3.0.3.2.2, respectively. The staff noted that the Water Chemistry Control – BWR and One-Time Inspection Programs propose to manage the aging of steel containment isolation and other ESF system components through the use of water chemistry controls and a one-time inspection using visual, ultrasonic, or surface techniques to ensure the effectiveness of the water chemistry control program. The staff also noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage aging through the use of periodic inspections, as least once every 5 years, using visual or other appropriate techniques. 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 Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs acceptable because the Water Chemistry Control – BWR Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection and Periodic Surveillance and Preventive Maintenance Programs include visual, ultrasonic, surface inspection, or other appropriate techniques capable of detecting general, pitting, and crevice corrosion.

The staff concludes that for LRA item 3.2.1-16, 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).

3.2.2.1.3 Loss of Material Due to 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, which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs to manage the aging effect for stainless steel components. 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. GALL Report AMPs XI.M2 and XI.M32 recommend using water chemistry controls and a one-time visual or volumetric inspection to manage aging.

The applicant stated that for item 3.2.1-17, the applicability is limited to stainless steel components. The staff noted that a search of the applicant's UFSAR confirmed that no in-scope aluminum components exposed to treated water are present in the ESF systems.

The staff's evaluations of the applicant's Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs are documented in SER Sections 3.0.3.1.41, 3.0.3.1.32, and 3.0.3.2.2, respectively. The staff noted that the Water Chemistry Control – BWR and One-Time Inspection Programs propose to manage the aging of stainless steel components through the use of water chemistry controls and a one-time inspection using visual, ultrasonic, or surface techniques to ensure the effectiveness of the water chemistry control program. The staff also noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage aging through the use of periodic inspections, as least once every 5 years, using visual or other appropriate techniques. 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 Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs acceptable because the Water Chemistry Control – BWR Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection and Periodic Surveillance and Preventive Maintenance Programs include visual, ultrasonic, surface inspection, or other appropriate techniques capable of detecting pitting and crevice corrosion.

The staff concludes that for LRA item 3.2.1-17, 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).

3.2.2.1.4 Cracking Due to Stress Corrosion Cracking

LRA Table 3.2.1, item 3.2.1-28 addresses stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water greater than 60 °C (greater than 140 °F) that will be managed for cracking due to SCC. The staff noted that the applicant also applied this item to nickel alloy reactor recirculation pump heat exchanger assembly subcomponents. For the AMR item that cites generic note C, the LRA credits the Inservice Inspection and Water Chemistry Control – Closed Treated Water Systems Programs to manage the aging effect for heat exchanger assembly components. The GALL Report recommends GALL Report AMP XI.M21A, "Closed Treated Water Systems," to ensure that this aging effect is adequately managed for stainless steel components. GALL Report AMP XI.M21A recommends using water chemistry controls and visual inspections to manage aging.

The staff reviewed the associated items in the LRA and considered whether the nickel alloy 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 addressed loss of material for this component, material, and environment combination in other AMR items in LRA Table 3.1.2-3. Based on its review of the ASM Handbook, Volume 13B, chapter on “Corrosion of Nickel and Nickel-Based Alloys” (ASM International, 2005), which states that nickel-base alloys are generally more resistant to SCC than stainless steels, but SCC can occur in specific environments, such as hot caustic, fluoride, and chloride-containing water, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff’s evaluations of the applicant’s Inservice Inspection and Water Chemistry Control – Closed Treated Water Systems Programs are documented in SER Sections 3.0.3.1.22 and 3.0.3.1.42, respectively. The staff noted that the Inservice Inspection Program proposes to manage the aging through the use of volumetric, surface, or visual examinations in accordance with the ASME Boiler and Pressure Vessel Code, Section XI. The staff also noted that the Water Chemistry Control – Closed Treated Water Systems Program proposes to manage the aging with water chemistry controls and opportunistic and periodic inspections. In its review of components associated with item 3.2.1-28 for which the applicant cited generic note C, the staff finds the applicant’s proposal to manage aging using the Inservice Inspection and Water Chemistry Control – Closed Treated Water Systems Programs acceptable because the water chemistry controls are capable of mitigating the environmental effects on cracking and the opportunistic and periodic inspections can detect the presence or extent of cracking before loss of intended function.

The staff concludes that for LRA item 3.2.1-28, 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 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.2.1, item 3.2.1-31 addresses stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed cycle cooling water, which will be managed for loss of material due to pitting and crevice corrosion. The staff noted that the applicant also applied this item to nickel alloy heat exchanger components. The LRA credits the Water Chemistry Control – Closed Treated Water Systems Program to manage the aging effect for heat exchanger assembly components. The GALL Report recommends GALL Report AMP XI.M21A, “Closed Treated Water Systems,” to ensure that this aging effect is adequately managed.

The staff reviewed the associated items in the LRA and considered whether the nickel alloy 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 addressed cracking for this component, material, and environment combination in other AMR items in LRA Table 3.1.2-3. Based on its review of GALL Report items VII.C3.AP-206 and VII.E5.AP-276, which state that nickel-based alloys are subject to loss of material when exposed to raw water and waste water, respectively, which do not contain the corrosion inhibitors present in closed-cycle cooling water, 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 applicant’s Water Chemistry Control – Closed Treated Water Systems Program is documented in SER Section 3.0.3.1.42. The staff finds the applicant’s proposal to manage loss of material using the Water Chemistry Control – Closed Treated Water Systems Program acceptable because the water chemistry controls are capable of mitigating the environmental effects on loss of material and the opportunistic and periodic inspections can detect the presence or extent of corrosion before loss of intended function.

The staff concludes that for LRA item 3.2.1-31, 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).

3.2.2.1.6 No Aging Effects Requiring Aging Management for Stainless Steel Piping, Piping Components, and Piping Elements Exposed to Air-Indoor Uncontrolled, Air with Borated Water Leakage, Concrete, or Gas

LRA Table 3.2.1, item 3.2.1-63 addresses stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (both internally and externally), air with borated water leakage, concrete, or gas and states that the items have no aging effects and no AMP is proposed. The GALL Report recommends that no aging effects are applicable and no AMP is recommended.

During its review of components associated with item number 3.2.1-63 for which the applicant cited generic note A, the staff noted that the LRA credits this item for stainless steel moisture separators exposed internally and externally to indoor air in LRA Table 3.2.2-6. There are no other environments listed for the moisture separator. The staff noted that moisture separators are usually exposed to air containing significant amounts of water, and parts may be exposed to water where the moisture accumulates. The GALL Report recommends that stainless steel components exposed to condensation or raw water be managed for loss of material. By letter dated May 24, 2012, the staff issued RAI 3.2.1.63-1 requesting that the applicant explain why the stainless steel moisture separator is not susceptible to any aging effects and does not require aging management.

In its response dated June 22, 2012, the applicant stated that the component is in the SGTS, which under normal operating conditions is in standby with an internal environment of indoor air that does not contain significant moisture. However, the staff noted that the applicant's definition of air-indoor states that it is air in an environment that is protected from precipitation. The LRA definition of air-indoor does not discuss the dew point or humidity of the air. SRP-LR Section A.1.2.1 states that aging effects should be considered that result from normal plant operation, including plant operating transients and shutdown. The staff noted that during normal operation, SGTSs are subject to periodic testing that is typically several hours in duration, and that the systems may be placed in-service at other times.

The staff finds the applicant's response unacceptable because it is unclear how condensation or the accumulation of moisture is prevented during times when the SGTS is placed in service such that wetting and drying of the internal surfaces does not occur. By letter dated July 27, 2012, the staff issued RAI 3.2.1.63-1a requesting that the applicant provide justification for why aging will not occur in the moisture separator during the period of extended operation, such as evidence of the absence of condensation and corrosion.

In its response dated August 21, 2012, the applicant stated that the drain valves for the moisture separators are open when the system is in operation, preventing accumulation of moisture. The applicant also stated that the inside of each moisture separator is cleaned and inspected every

2 years. The applicant further stated that the inspections in 2010 and 2011 documented that each moisture separator was clean with no corrosion present, which justifies why the components have no aging effects requiring management.

The staff finds the applicant's response acceptable because the moisture separators are normally in standby exposed to indoor air; when they are placed in service, moisture does not accumulate within the separators; the plant indoor air does not normally contain contaminants, such as chlorides, that would cause loss of material or cracking in stainless steel components if allowed to condense; and the inspections of the moisture separators have found no evidence of aging. The staff's concerns described in RAI 3.2.1.63-1 and 3.2.1.63-1a are resolved.

The staff concludes that for LRA item 3.2.1-63, 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).

3.2.2.1.7 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed are not applicable. On the basis of its review, the staff concludes that the AMR results which the applicant claimed are not applicable are not applicable to GGNS.

As discussed in SER Section 3.2.2.1, 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 due to cladding breach
- loss of material due to pitting and crevice corrosion
- loss of material due to erosion
- loss of material due to general corrosion and fouling that leads to corrosion
- cracking due to 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 in the engineered-safety systems and is 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 that 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, except as identified below.

The staff reviewed the applicant's AMR results in the associated LRA tables within LRA Sections 3.2, 3.3, and 3.4. For LPCS system, HPCS system, SLC system, suppression pool makeup system, and SGTS, UFSAR Table 3.2-1 indicates these systems are non-Class 1 and the staff noted that there may be components that have been analyzed for cumulative fatigue damage. It is not clear to the staff why those components that may have been analyzed for cumulative fatigue damage, as discussed in LRA Section 4.3.2, are not included as AMR items in applicable tables in LRA Sections 3.2, 3.3 and 3.4.

By letter dated June 20, 2012, the staff issued RAI 3.2.2-1 requesting the applicant to justify that LRA Tables 3.2, 3.3, and 3.4 do not need to identify and list all the AMR results for non-Class 1 piping associated with a TLAA for managing the aging effect of cumulative fatigue damage.

In its response dated July 19, 2012, the applicant stated that the non-Class 1 portions of the LPCS system, HPCS system, SLC system, suppression pool makeup system, and SGTS have normal temperatures below the temperature threshold for fatigue. The applicant explained that there are no fatigue time-limited aging analyses for these systems and no fatigue AMR items. The staff noted that thermal stress is proportional to the change of temperature from the reference temperature. When the system temperature is low, the difference between the reference temperature and system temperature is small; thus, the resulting thermal stress is small and metal fatigue would not be an aging effect required for managing these systems.

Based on its review, the staff finds the applicant's response to RAI 3.2.2-1 acceptable because the applicant justified that AMR results are not required to identify metal fatigue as an aging effect for the non-Class 1 portions of the LPCS system, HPCS system, SLC system, suppression pool makeup system, and SGTS and that metal fatigue of these systems is not an aging effect requiring management due to low system temperature, as explained above. The staff's concern described in RAI 3.2.2-1 is resolved.

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 due to 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 and 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 3.2.2.2.3.1, associated with LRA Table 3.2.1, item 3.2.1-3, addresses loss of material due to pitting and crevice corrosion in partially encased stainless steel tanks exposed to raw water. The applicant stated that this item is not applicable because the ESF systems do not include partially encased stainless steel tanks exposed to this environment. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR and finds that no in-scope partially encased stainless steel tanks exposed to raw water are present in the ESF systems.

(2) LRA Section 3.2.2.2.3, which is 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 that will be managed for loss of material due to pitting and crevice corrosion. The applicant stated that this item is not applicable because there are no in-scope stainless steel components exposed to outdoor air or located near unducted air intakes in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and finds that no in-scope stainless steel piping, piping components, piping elements and tanks exposed to air-outdoor are present in the ESF systems.

3.2.2.2.4 Loss of Material Due to Erosion

LRA Section 3.2.2.2.4, associated with LRA Table 3.2.1, item 3.2.1-5, addresses loss of material in stainless steel minimum flow recirculation orifices exposed to treated borated water for PWR high pressure safety injection 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 GGNS.

3.2.2.2.5 Loss of Material Due to 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 due to general corrosion and fouling for steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to indoor air. The applicant stated that this item is not applicable because the containment spray nozzles are stainless steel. The applicant also stated that there are no steel orifices in the containment spray subsystem of the RHR system internally exposed to an indoor air environment. The staff reviewed LRA

Sections 2.3.2 and 3.2 and the UFSAR and finds that no in-scope steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to indoor air are present in the ESF systems.

3.2.2.2.6 Cracking Due to Stress Corrosion Cracking

LRA Section 3.2.2.2.6, which is associated with LRA Table 3.2.1 item 3.2.1-7, addresses stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor that will be managed for cracking due to SCC. The applicant stated that this item is not applicable because there are no in-scope stainless steel components exposed to outdoor air or located near unducted air intakes in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and finds that no in-scope stainless steel piping, piping components, piping elements and tanks exposed to air-outdoor are 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.

3.2.2.2.8 Loss of Material Due to Recurring Internal Corrosion

By letter dated May 13, 2014, the applicant addressed recurring internal corrosion that is described in Section A and Appendix B of LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation." LR-ISG-2012-02 includes a new section (Section 3.2.2.2.9, Loss of Material Due to Recurring Internal Corrosion) in the SRP-LR for "AMR Results for Which Further Evaluation Is Recommended by the GALL Report."

Based on its review of plant-specific operating experience for the past 5 years, the applicant stated that microbiologically-influenced corrosion of piping components is a recurring internal corrosion issue, as defined in LR-ISG-2012-02, Section A. The applicant also stated that it monitors loss of material in piping components due to microbiologically-influenced corrosion in the CW, SSW, plant service water, and fire protection systems. Based on this, the staff determines that recurring internal corrosion is not applicable to the ESF section, because these systems are addressed in the Auxiliary System, Section 3.3, and Steam and Power Conversion Systems, Section 3.4, of the LRA.

3.2.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-8, 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 3.2.2-8, 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 Residual Heat Removal - 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 RHR 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 Low Pressure 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 Low Pressure Core Spray component groups.

Carbon Steel Piping Components Exposed to Treated Water. By letter dated December 18, 2012, the applicant revised LRA Tables 3.2.2-2, 3.2.2-3, 3.2.2-8-2, and 3.2.2-8-3 and stated that carbon steel piping components exposed to treated water will be managed for loss of material by the Flow-Accelerated Corrosion Program. The AMR items cite generic note H and also cite plant-specific note 204, which states that the Flow-Accelerated Corrosion Program also manages loss of material due to erosion mechanisms other than flow-accelerated corrosion.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel piping components exposed to treated water are susceptible to loss of material due to general, pitting, crevice, and flow-accelerated corrosion and recommends GALL Report AMP XI.M2, AMP XI.M32, and AMP XI.M17 to manage the aging effect due to these mechanisms. However the applicant has identified additional aging mechanisms. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in other AMR items in LRA Tables 3.2.2-2, 3.2.2-3, 3.2.2-8-2, and 3.2.2-8-3.

The staff's evaluation of the applicant's Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.1.21. The staff finds the applicant's proposal to manage loss of material due to erosion mechanisms other than flow-accelerated corrosion using the Flow-Accelerated Corrosion Program acceptable, because the associated components can be treated similar to "susceptible-not-modeled" components currently within the program, which ensures that the consequent wall thinning will be detected before loss of intended function.

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 Core Spray - 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 HPCS component groups.

Carbon Steel Piping Components Exposed to Treated Water. The staff's evaluation for carbon steel piping components exposed to treated water, which will be managed for loss of material due to erosion mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.2.2.3.2.

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).

3.2.2.3.4 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 RCIC component groups.

In LRA Table 3.2.2-4, the applicant stated there are TLAAs for stainless steel orifice and tubing exposed to steam, which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

Stainless steel heat exchanger exposed to lubricating oil. In LRA Table 3.2.2-4, the applicant stated that stainless steel heat exchanger tubesheets, heat exchanger tubes, orifice, tubing, and valve bodies exposed to lubricating oil will be managed for cracking by the Oil Analysis Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that stainless steel heat exchanger tubesheets, heat exchanger tubes, orifice, tubing, and valve bodies exposed to lubricating oil are susceptible to loss of material and recommends GALL Report AMP XI.M39 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).

3.2.2.3.5 Pressure Relief – Summary of Aging Management Review – LRA Table 3.2.2-5

The staff reviewed LRA Table 3.2.2-5, which summarizes the results of AMR evaluations for the pressure relief component groups.

In LRA Table 3.2.2-5, the applicant stated that there are TLAAs for stainless steel thermowell, tubing, and valve body exposed to steam, which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

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. 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.

3.2.2.3.7 Containment Penetrations – Summary of Aging Management Review – LRA Table 3.2.2-7

The staff reviewed LRA Table 3.2.2-7, which summarizes the results of AMR evaluations for the containment penetrations component groups.

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. In LRA Tables 3.2.2-7, 3.3.2-7, 3.3.2-9, 3.3.2-14, 3.3.2-19-19, 3.3.2-19-25, and 3.3.2-19-26, the applicant stated that stainless steel piping components, such as tubing, thermowells and value bodies, exposed to external condensation will be managed for loss of material by the External Surfaces Monitoring Program. As amended by letter dated October 25, 2013, the applicant revised LRA Table 3.3.2-9 to include stainless steel sight glasses exposed to external condensation, which will also be managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects the applicant proposed 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 exposed to condensation should be age 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 applicant's External Surfaces Monitoring is documented in SER Section 3.0.3.1.17. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring acceptable because the AMP includes visual inspections capable of detecting loss of material in stainless components exposed to external condensation.

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).

3.2.2.3.8 Miscellaneous ESF Systems in Scope for 10 CFR 54.4(a)(2) – Summary of Aging Management Review – LRA Table 3.2.2-8

The staff reviewed LRA Tables 3.2.2-8-1 through 3.2.2-8-4, which summarizes the results of AMR evaluations for the miscellaneous ESF systems in scope for 10 CFR 54.4(a)(2) component groups.

For LRA Tables 3.2.2-8-2 and 3.2.2-8-3

Carbon Steel Piping Components Exposed to Treated Water. The staff's evaluation for carbon steel piping components exposed to treated water, which will be managed for loss of material due to erosion mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.2.2.3.2.

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).

3.2.3 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 section of the SER documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups of:

- CRD
- SLC
- suppression pool makeup
- leakage detection and control
- combustible gas control
- fuel pool cooling and cleanup
- SSW
- component cooling water
- plant service water
- floor and equipment drainage
- compressed air
- fire protection – water
- fire protection – Halon and CO_2
- plant chilled water
- standby diesel generator
- HPCS diesel generator

- control room Heating, Ventilation, and Air Conditioning (HVAC)
- HVAC
- miscellaneous auxiliary systems in scope for 10 CFR 54.4(a)(2)

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 which 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 System Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to 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 due to 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 due to stress corrosion cracking; cyclic loading	Chapter XI.M2, “Water Chemistry” The AMP is to be augmented by verifying the absence of cracking due to 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	Not applicable	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 due to stress corrosion cracking	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	Yes	Not applicable	Not applicable to GGNS (see Section 3.3.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	No	Not applicable	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 due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Not applicable	Not applicable to GGNS (see Section 3.3.2.2.5)
Stainless steel high-pressure pump, casing exposed to treated borated water (3.3.1-7)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Not applicable	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 due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Not applicable	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 due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Not applicable	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 due to stress corrosion cracking; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to GGNS (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 due to stress corrosion cracking; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to GGNS (see Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to 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 (3.3.1-13)	Loss of material due to general corrosion	Chapter XI.M18, “Bolting Integrity”	No	Not applicable	Not applicable to GGNS (see 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 due to 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 exposed to treated water >60 °C (>140 °F) (3.3.1-16)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M25, “BWR Reactor Water Cleanup System”	No	Not applicable	Not applicable to GGNS (see Section 3.3.2.1.1)
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-17)	Reduction of heat transfer due to fouling	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry Control – BWR and One-Time Inspection	Consistent with the GALL Report
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 due to stress corrosion cracking	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
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 due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Stainless steel; steel with stainless steel cladding, aluminum piping, piping components, and piping elements, exchanger components exposed to treated water, sodium pentaborate solution (3.3.1-25)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance	Consistent with the GALL Report (see SER Section 3.3.2.1.2)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to pitting and crevice corrosion (only for steel after lining/cladding degradation)	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to GGNS (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 due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to GGNS (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; tanks exposed treated water >60 °C (>140 °F), treated borated water >60 °C (>140 °F) (3.3.1-28)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to GGNS (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 due to aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to GGNS (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 due to water absorption	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to settling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to GGNS (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 due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to GGNS (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 due to elastomer degradation; loss of material due to erosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.3)
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-33)	Loss of material due to abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Nickel alloy, copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-34)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to GGNS (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 due to general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Service Water Integrity	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-36)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Service Water Integrity	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with coating or lining) piping, piping components, and piping elements exposed to raw water (3.3.1-37)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion; lining/coating degradation	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report
Copper alloy, steel heat exchanger components exposed to raw water (3.3.1-38)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1.4)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-39)	Loss of material due to pitting and crevice corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-41)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity	Consistent with the GALL Report
Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water (3.3.1-42)	Reduction of heat transfer due to fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Service Water Integrity and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.5)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-43)	Cracking due to stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to stress corrosion cracking	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to GGNS (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 due to general, pitting, and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – 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 due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – 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 due to microbiologically-influenced corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report (see SER Section 3.3.2.1.6)
Aluminum piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-48)	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to GGNS (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 due to pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – 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 due to fouling	Chapter XI.M21A, “Closed Treated Water Systems”	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to boraflex degradation	Chapter XI.M22, “Boraflex Monitoring”	No	Boraflex Monitoring	Consistent with the GALL Report
Steel cranes; rails and structural girders exposed to air – indoor, uncontrolled (external) (3.3.1-52)	Loss of material due to 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 due to wear	Chapter XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Copper alloy piping, piping components, and piping elements exposed to condensation (3.3.1-54)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M24, “Compressed Air Monitoring”	No	Compressed Air Monitoring	Consistent with the GALL Report
Steel piping, piping components, and piping elements: compressed air system exposed to condensation (internal) (3.3.1-55)	Loss of material due to 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 due to pitting and crevice corrosion	Chapter XI.M24, “Compressed Air Monitoring”	No	Compressed Air Monitoring	Consistent with the GALL Report
Elastomers fire barrier penetration seals exposed to air – indoor, uncontrolled, air – outdoor (3.3.1-57)	Increased hardness; shrinkage; loss of strength due to weathering	Chapter XI.M26, “Fire Protection”	No	Fire Protection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to 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 due to wear	Chapter XI.M26, "Fire Protection"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Reinforced concrete structural fire barriers: walls, ceilings, and floors exposed to air – indoor, uncontrolled (3.3.1-60)	Concrete cracking and spalling due to 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 due to 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
Reinforced concrete structural fire barriers: walls, ceilings, and floors exposed to air – indoor, uncontrolled, air – outdoor (3.3.1-62)	Loss of material due to corrosion of embedded steel	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Steel fire hydrants exposed to air – outdoor (3.3.1-63)	Loss of material due to 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 due to general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Fire Water System	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to raw water (3.3.1-65)	Loss of material due to pitting and crevice corrosion	Chapter XI.M27, "Fire Water System"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 (3.3.1-66)	Loss of material due to pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Steel tanks exposed to air – outdoor (external) (3.3.1-67)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report (see SER Section 3.3.2.1.17)
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1-68)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Diesel Fuel Monitoring and One-Time Inspection	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to fuel oil (3.3.1-69)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Diesel Fuel Monitoring and One-Time Inspection	Consistent with the GALL Report
Steel piping, piping components, and piping elements; tanks exposed to fuel oil (3.3.1-70)	Loss of material due to 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	Diesel Fuel Monitoring and One-Time Inspection	Consistent with the GALL Report
Stainless steel, aluminum piping, piping components, and piping elements exposed to fuel oil (3.3.1-71)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Diesel Fuel Monitoring 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 due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching	Consistent with the GALL Report (see SER Sections 3.3.2.1.7 and 3.3.2.1.8)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 air – outdoor (3.3.1-73)	Changes in material properties due to aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to GGNS (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 due to settling	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to air – outdoor (3.3.1-75)	Cracking due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Elastomer seals and components exposed to air – indoor, uncontrolled (internal/external) (3.3.1-76)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to air – outdoor (3.3.1-77)	Loss of material due to abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to GGNS (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 due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring, Fire Protection, and Service Water Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1.9)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 condensation (external) (3.3.1-79)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring	Consistent with the GALL Report
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 due to general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring	Consistent with the GALL Report
Copper alloy, aluminum piping, piping components, and piping elements exposed to air – outdoor (external), air – outdoor (3.3.1-81)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring, Fire Protection, and Service Water Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1.9)
Elastomers Elastomer: seals and components exposed to air – indoor, uncontrolled (external) (3.3.1-82)	Loss of material due to wear	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Consistent with the GALL Report (see SER Section 3.3.2.1.1)
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-83)	Cracking due to stress corrosion cracking	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.10)
Elastomers Elastomer seals and components exposed to closed-cycle cooling water (3.3.1-85)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	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 due to elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to general (steel only), pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.11)
Steel, copper alloy piping, piping components, and piping elements exposed to moist air or condensation (internal) (3.3.1-89)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
Steel ducting and components (internal surfaces) exposed to condensation (internal) (3.3.1-90)	Loss of material due to 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	Internal Surfaces in Miscellaneous Piping and Ducting Components and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
Steel piping, piping components, and piping elements; tanks exposed to waste water (3.3.1-91)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components and Periodic Surveillance and Preventive Maintenance	Consistent with the GALL Report (see SER Section 3.3.2.1.13 and 3.3.2.1.14)
Aluminum piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-92)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Compressed Air Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.14)
Copper alloy piping, piping components, and piping elements exposed to raw water (potable) (3.3.1-93)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Stainless steel ducting and components exposed to condensation (3.3.1-94)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Internal Surfaces in Miscellaneous Piping and Ducting Components and Periodic Surveillance and Preventive Maintenance	Consistent with the GALL Report (see SER Section 33.3.2.1.16)
Elastomers Elastomer: seals and components exposed to air – indoor, uncontrolled (internal) (3.3.1-96)	Loss of material due to wear	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Consistent with the GALL Report (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 due to general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Oil Analysis, One-Time Inspection, and Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.17)
Steel heat exchanger components exposed to lubricating oil (3.3.1-98)	Loss of material due to 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	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 due to pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-100)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Oil Analysis and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum heat exchanger tubes exposed to lubricating oil (3.3.1-101)	Reduction of heat transfer due to fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Boral®; boron steel, and other materials (excluding boraflex); 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-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	Chapter XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to soil or concrete (3.3.1-103)	Cracking due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (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 due to water absorption	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (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 due to exposure of rebar	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete (3.3.1-106)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried Piping and Tanks	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.3.1-107)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Steel bolting exposed to soil or concrete (3.3.1-109)	Loss of material due to general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried 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 due to general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (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 due to stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
Steel structural steel exposed to air – indoor, uncontrolled (external) (3.3.1-111)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Consistent with the GALL Report
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 operating experience indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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 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	Not applicable	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	Not applicable	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	Not applicable	Not applicable to GGNS (see SER Section 3.3.2.1.1)
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	Not applicable	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	Not applicable	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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	Not applicable	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	Not applicable	Consistent with the GALL Report
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 GGNS (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 GGNS (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
- Boraflex Monitoring
- Buried Piping and Tanks Inspection
- Compressed Air Monitoring
- Diesel Fuel Monitoring
- External Surfaces Monitoring
- Fire Protection
- Fire Water System
- Flow-Accelerated Corrosion
- Internal Surfaces in Miscellaneous Piping and Ducting Components
- Oil Analysis
- One-Time Inspection
- Periodic Surveillance and Preventive Maintenance
- Selective Leaching
- Service Water Integrity
- Water Chemistry Control – BWR
- Water Chemistry Control – Closed Treated Water Systems

LRA Tables 3.3.2-1 through 3.3.2-19 summarize AMRs for the auxiliary system components and indicate AMRs 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.

3.3.2.1.1 AMR Results Identified as Not Applicable

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 stated 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 that these items are not applicable to GGNS.

For LRA Table 3.3.1, items 3.3.1-10, 3.3.1-11, 3.3.1-16, 3.3.1-18, 3.3.1-19, 3.3.1-27 through 3.3.1-33, 3.3.1-44, 3.3.1-48, 3.3.1-65, 3.3.1-66, 3.3.1-73 through 3.3.1-75, 3.3.1-77, 3.3.1-94, 3.3.1-101 through 3.3.1-108, 3.3.1-111, 3.3.1-122, and 3.3.1-123, the applicant stated that the corresponding items in the GALL Report are 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.

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 due to general corrosion for this component group. The applicant stated that this item is not applicable because steam or water leakage is not considered a separate aspect of the indoor air environment. The staff evaluated the applicant's claim and found it acceptable because (a) all ESF system bolting exposed to air is being managed for loss of material by the Bolting Integrity Program using item 3.3.1-12, (b) the program conducts periodic visual inspections capable of detecting loss of material due to general corrosion in bolting, and (c) use of this program 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 due to pitting and crevice corrosion for this component group. The applicant stated that these items are 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 GALL Report recommendations.

LRA Table 3.3.1, item 3.3.1-26, addresses steel with elastomer lining and steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection." to manage loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation) for this component group. The applicant stated that this item was not used because elastomer linings are not credited for protection of piping in scope for license renewal. The staff evaluated the applicant's claim and finds it acceptable because although the applicant has stated that they have not used this item, a review of the LRA application for all LRA Section 3.3 systems with carbon steel piping, piping components, or piping elements exposed to treated water, being managed for loss of material, demonstrated that appropriate AMPs are being used. With the exception of three AMR items associated with the Internal Surfaces in Miscellaneous Piping and Ducting Components Program, the applicant uses a water chemistry program (i.e., Water Chemistry Control – BWR or Water Chemistry Control – Close Treated Water System) and either the One-Time Inspection Program or the water chemistry program includes a periodic inspection program, or the AMR item uses a periodic inspection program (i.e., Flow-Accelerated Corrosion, Internal Surfaces in Miscellaneous Piping and Ducting Components). In the case of the AMR items associated with the Internal Surfaces in Miscellaneous Piping and Ducting Components, these components are a filter housing, tank and valve body in the domestic water system which cite plant-specific note 307, which states, "[t]his treated water is equivalent to the NUREG-1801 raw water (potable) environment." The GALL Report, item AP-101 recommends only GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage aging of the elastomeric material exposed to treated water. Likewise, item AP-270 also only recommends AMP XI.M38 for steel items exposed to raw water (potable). In summary, the applicant is using the appropriate AMPs to manage all the applicable components.

LRA Table 3.3.1, item 3.3.1-34, addresses nickel alloy and copper-alloy piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” to manage for loss of material due to general, pitting, and crevice corrosion. The applicant stated that this item was not used, because there are no nickel alloy components exposed to raw water in auxiliary systems and the associated copper-alloy piping components are addressed in item 3.3.1-35 and 3.3.1-36. The staff reviewed LRA Section 2.3.2, and 3.2, and the UFSAR and finds that no in-scope nickel alloy piping components exposed to raw water are present in the auxiliary systems. The staff evaluated the applicant’s claim and found it acceptable because the staff confirmed that copper-alloy piping components exposed to raw water in the auxiliary systems reference either LRA item 3.3.1-35 or 3.3.1-36, which manage for loss of material in a manner consistent with LRA items 3.3.1-34 and the GALL Report recommendations.

LRA Table 3.3.1, items 3.3.1-39 address 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 due to pitting and crevice corrosion for this component group. The applicant stated that this item was not used because this component group is addressed with LRA items 3.3.1-40 and 3.3.1-41. The staff noted that LRA items 3.3.1-40 and 3.3.1-41 are similar to item 3.3.1-39, but these items are being managed for the additional aging effects of loss of material due to fouling that leads to corrosion, and microbiologically-influenced 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 either LRA item 3.3.1-40 or 3.3.1-41, which manage for loss of material in a manner consistent with LRA items 3.3.1-39, and the GALL Report recommendations.

LRA Table 3.3.1, item 3.3.1-53 addresses steel cranes: rails and structural girders exposed to air- indoor, uncontrolled (external). The GALL Report recommends GALL Report AMP XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems,” to manage loss of material due to wear for this component group. The applicant stated that this item is not applicable because wear of crane rails due to rolling or sliding wheels is not expected in any measurable amount owing to infrequent crane use. The staff evaluated the applicant’s claim and finds it acceptable because although the loss of material due to wear aging effect will not be specifically managed, the loss of material due to general corrosion aging effect will be managed under this AMP, which will monitor the condition of the steel crane rails, including the effects of wear if it were to occur.

LRA Table 3.3.1, item 3.3.1-59 addresses steel fire rated doors exposed to air-outdoor or air-indoor uncontrolled. The GALL Report recommends GALL Report AMP XI.M26, “Fire Protection,” to manage loss of material due to wear for this component group. The applicant stated that this item is not applicable because wear is an event driven effect and wear will not occur if a fire door is properly designed and maintained. The staff noted that loss of material is applicable since fire doors are designed for frequent repetitive motion that can result in wear. However, the staff also noted that in LRA Table 3.5.2-4, the applicant stated that carbon steel fire doors exposed to air-indoor uncontrolled and air-outdoor will be managed for loss of material by the Fire Protection Program. The staff evaluated the applicant’s claim and finds it acceptable because the applicant will manage loss of material using the Fire Protection Program and the methods for managing loss of material for fire doors are the same regardless of the aging mechanism.

LRA Table 3.3.1, item 3.3.1-62 addresses reinforced concrete structural fire barrier walls, ceilings, and floors exposed to air-outdoor or air-indoor uncontrolled. The GALL Report recommends GALL Report AMP XI.M26, "Fire Protection," and XI.S6, "Structures Monitoring," to manage loss of material due to corrosion of embedded steel for this component group. The applicant stated that this item is not applicable because the concrete structural fire barriers are designed in accordance with ACI and ASTM standards that provide for good quality, high-strength, dense, low permeability concrete, and the concrete provides sufficient cover to prevent corrosion of the embedded steel. The staff noted that dense, low permeability concrete does not prevent loss of material from occurring. However, the staff also noted that all of the concrete fire barriers in the LRA are being managed for aging using the Fire Protection and Structures Monitoring Programs, regardless of whether the items claim to have any aging effects. The AMR items cite LRA Table 3.3.1, items 3.3.1-60 or 3.3.1-61. The staff evaluated the applicant's claim and finds it acceptable because, regardless of whether the items claim to have any aging effects, the applicant will manage aging for its concrete structural fire barriers using the Fire Protection and Structures Monitoring Programs, which is consistent with the GALL Report recommendations.

LRA Table 3.3.1, items 3.3.1-82 and 3.3.1-96 address elastomer seals and components exposed to air-indoor, uncontrolled (external) and air-indoor, uncontrolled (internal), respectively, that are being managed for loss of material due to wear. The GALL Report recommends GALL Report AMP XI.M36 "External Surfaces Monitoring of Mechanical Components" and GALL Report AMP XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," respectively, to manage loss of material due to wear for this component group. The applicant stated that this item is not applicable because, "[w]ear of elastomer components is considered an event driven condition rather than an aging effect. If the elastomer component is properly designed, installed and maintained, contact with other surfaces leading to wear will not occur." The staff evaluated the applicant's claim and determined that it lacks sufficient information to find it acceptable because the conclusion that properly designed, installed, and maintained components will not experience wear is not consistent with the GALL Report definition of wear. By letter dated June 20, 2012, the staff issued RAI 3.3.1.82-1 requesting that the applicant state whether any in-scope elastomeric components (a) are exposed to an internal or external environment that includes hard abrasive particles; (b) are susceptible to wear that over time, due to their frequent manipulation, could challenge the intended function(s) of the component; and (c) are designed with clamped joints where relative motion is not intended; however, they are susceptible to wear over time due to a loss of the clamping force, which could challenge the intended function(s) of the component; and if an AERM is applicable based on the configurations or aging mechanisms described in items (a) through (c), discuss how the AERM will be managed.

In its response dated July 19, 2012, the applicant stated that for flexible duct connections in LRA Tables 3.2.2-6, 3.3.2-17, 3.3.2-18, 3.3.2-19-10, 3.3.2-19-11, 3.3.2-19-31, 3.3.2-19-32, 3.3.2-19-34, and 3.3.2-19-36, the indoor air environment on the external surfaces of the ducting does not contain hard abrasive particles. However, the joints are susceptible to frequent manipulation due to the frequent cycling of ventilation systems and relative motion due to loss of clamping force. New AMR items have been included in the above cited tables that address the external surfaces of elastomeric flexible duct connections being managed for loss of material due to wear by the External Surfaces Monitoring and Internal Surfaces in Miscellaneous Piping and Ducting Components Programs, citing item 3.3.1-82 with generic note A and item 3.3.1-96 with generic note A, respectively.

The staff finds the applicant's response associated with the external and internal environment of flexible duct connections acceptable because the applicant has revised its LRA to include external and internal wear as an aging effect and, consistent with the GALL Report, the External Surfaces Monitoring and Internal Surfaces in Miscellaneous Piping and Ducting Components Programs will be used to manage aging.

In its response to RAI 3.3.1.82-1 dated July 19, 2012, the applicant also addressed elastomeric expansion joints as follows. The applicant stated that the elastomeric expansion joints cited in LRA Table 3.4.2.2-19 are periodically replaced and are not subject to AMR, as documented in its response to RAI 2.3.4.1-2, dated June 11, 2012. The staff's evaluation of the applicant's response to RAI 2.3.4.1-2 is documented in SER Section 2.3.4.1.2. In its response to RAI 3.3.1-82, the applicant also stated that the drywell chilled water expansion joints cited in LRA Table 3.3.2-19-26 and CW expansion joints cited in LRA Table 3.4.2.2-18 are not subject to frequent cycling because the systems are continuously in use, and the joints are not susceptible to wear from loss of clamping force because they are bolted joints. The applicant further stated that the external indoor air environment does not contain hard abrasive particles. The internal environment for the drywell chilled water expansion joints is treated water. The internal environment for the CW expansion joints is raw water that can result in erosion of the elastomeric material. LRA Table 3.4.2-2-18 was amended to include loss of material as an aging effect for elastomeric expansion joints exposed to raw water being managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components. The new item cites item 3.3.1-32.5 and generic note E because the GALL Report, item AP-76 recommends using AMP XI.M20, "Open-Cycle Cooling Water System," to manage loss of material due to erosion. The staff noted that the scope of AMP XI.M20 includes systems that transfer heat to the ultimate heat sink; therefore, the CW expansion joints would not be in the scope of the applicant's Service Water Integrity Program.

The staff finds the applicant's response associated with the external environment of expansion joints acceptable because the systems are not subject to frequent cycling and therefore the components are not being routinely manipulated, the bolted joint configuration minimizes the potential for loss of clamping force due to the uniform loading of the flanged connection, and the indoor air environment does not contain hard abrasive particles. The staff finds the applicant's response associated with the internal environment of expansion joints acceptable because the systems are not subject to frequent cycling and therefore the components are not being routinely manipulated, the bolted joint configuration minimizes the potential for loss of clamping force due to the uniform loading of the flanged connection, the indoor air and treated water environments do not contain hard abrasive particles and therefore there is no aging effect for this environment, and loss of material for the raw water environment is being managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components, which includes periodic opportunistic visual inspections capable of detecting loss of material. The staff's concerns described in RAI 3.3.1.82-1 are resolved.

LRA Table 3.3.1, item 3.3.1-109.5 addresses aluminum, copper-alloy, stainless steel, and steel underground piping, piping components, and piping elements. The GALL Report recommends GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," to manage loss of material due to general (steel only), pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because, "[t]here are no underground aluminum, copper-alloy, stainless steel or steel components in systems in the scope of license renewal." The staff evaluated the applicant's claim and lacked sufficient information to find it acceptable because an enhancement to LRA Section B.1.18, External Surfaces Monitoring Program, states that instructions will be provided for inspecting all underground components within the scope of this program. Based on the staff's review during the AMP audit, the fuel oil pump discharge check valve is one of the underground piping components associated with this enhancement. By letter dated April 16, 2012, the staff issued RAI B.1.5-1 requesting that the applicant provide a list of all underground in-scope components, state which AMP will be used to manage the aging of these underground in-scope components, and if a program other than the Buried Piping and Tanks Inspection Program will be used to age manage any of the underground components to state if any recommendations contained in AMP XI.M41 of the GALL Report will not be met and justify not meeting the recommendations. The applicant's response and staff evaluation of this RAI is documented in SER Section 3.0.3.1.4. The staff's concern described in RAI B.1.5-1 is resolved and the staff finds the applicant's use of item 3.3.1-78, which recommends the External Surfaces Monitoring Program to manage the fuel oil transfer pump discharge check valve, acceptable.

LRA Table 3.3.1, item 3.3.1-110 addresses stainless steel piping, piping components, and piping elements exposed to treated water greater than 60 °C (140 °F). The GALL Report recommends GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry," to manage cracking due to SCC for this component group. The applicant stated that this item is not used because stainless steel components of the auxiliary systems subject to evaluation under the BWR Stress Corrosion Cracking Program were reviewed as part of the Class 1 RCPB.

In its review, the staff determined the need for clarification of whether the scope of the applicant's BWR Stress Corrosion Cracking Program includes piping and piping welds regardless of ASME Code classification, consistent with GALL Report AMP XI.M7. The staff noted that LRA Section B.1.9 for the BWR Stress Corrosion Cracking Program includes the RCPB components 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.

By letter dated April 3, 2012, the staff issued RAI B.1.9-1 requesting that the applicant clarify whether the scope of the BWR Stress Corrosion Cracking Program includes non-Class 1 piping and piping welds made of austenitic stainless steel and nickel alloy materials. The staff also requested that if not included, the applicant justify why non-Class 1 piping and piping welds are excluded from the scope of the BWR Stress Corrosion Cracking Program.

In its response dated May 1, 2012, the applicant clarified that the BWR Stress Corrosion Cracking Program applies to relevant BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of code classification, consistent with the GALL Report as described in LRA Section B.1.9. The applicant also clarified that non-Class 1 piping and piping welds were not excluded from the program. The applicant further clarified that all components at GGNS included in the scope of this program are part of the RCPB and were subject to an AMR. In addition, the applicant indicated that the results of the AMR of these RCPB components are documented in LRA Tables 3.1.2-1 and 3.1.2-3.

In its review of the applicant's response to RAI B.1.9-1, the staff noted that the applicant clarified that its BWR Stress Corrosion Cracking Program applies to the relevant BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of code classification, consistent with the GALL Report. However, LRA item 3.3.1-110 indicates that the components in the auxiliary systems, subject to the BWR Stress Corrosion Cracking Program, were reviewed as part of the RCPB. Therefore, the staff needed justification as to why the components associated with LRA item 3.3.1-110 were reviewed as part of the RCPB, which consists of Class 1 components as discussed in LRA Section 2.3.1.2.

By letter dated July 23, 2012, the staff issued RAI B.1.9-1a requesting that the applicant justify why LRA Sections B.1.9 and A.1.9 indicate that the BWR Stress Corrosion Cracking Program manages only aging of the RCPB in contrast with the program scope recommended in the GALL Report that includes relevant piping and piping welds regardless of code classification. The staff also requested that the applicant clarify why LRA item 3.3.1-110 indicates that the components in the auxiliary systems, subject to the BWR Stress Corrosion Cracking Program, were reviewed as part of the RCPB, rather than against the relevant piping and piping welds (regardless of code classification).

In its response dated August 15, 2012, the applicant stated that there are no piping components or piping welds made of austenitic stainless steel or nickel alloy that are 4 inches or larger in nominal diameter and contain reactor coolant at a temperature above 93°C (200°F) during power operation in the non-Class 1 portions of the auxiliary systems. The applicant further provided revisions to LRA item 3.3.1-110 to clarify that there are no components outside the reactor coolant pressure boundary subject to the BWR Stress Corrosion Cracking Program requirements. The staff finds that the applicant's response acceptable because the applicant confirmed that the auxiliary systems have no non-Class 1 components that should be included in the scope of the applicant's BWR Stress Corrosion Cracking Program. The staff's concern described in RAIs B1.9-1 and B.1.9-1a is resolved.

The staff concludes that for LRA item 3.3.1-110, 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 3.3.1, item 3.3.1-116 addresses galvanized steel piping, piping components, and piping elements exposed to air-indoor, uncontrolled. The GALL Report recommends that there are no aging effects, aging mechanisms, or AMPs. The applicant stated that this item is not applicable because the galvanized steel coating of some steel components were not credited for corrosion protection for license renewal. The staff noted that the LRA includes AMR evaluations for steel components exposed to indoor air that reference LRA Table 3.2.1, item 2.1-44 and LRA Table 3.3.1, items 3.2.1-78, and 3.2.1-80 and credit the External Surfaces Monitoring Program for external surfaces and the Internal Surfaces in Miscellaneous Piping and Ducting Components Program for internal surfaces to manage loss of material in auxiliary systems. The staff evaluated the applicant's claim and finds it acceptable because the applicant chose to evaluate the subject components as being constructed of a more susceptible material, referencing appropriate alternative Table 1 items and managing aging consistent with GALL Report recommendations for those Table 1 items.

LRA Table 3.3.1, item 3.3.1-117 addresses glass piping elements exposed to uncontrolled indoor air, lubricating oil, closed-cycle cooling water, outdoor air, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, and gas. The applicant stated that it is consistent with the GALL Report for glass components exposed to indoor air, condensation, gas, and treated water, but that for other environments there are no glass components within auxiliary systems that are within the scope of license renewal. SRP-LR Table 3.3-1, item 3.3.1-117 states that there are no aging effects, aging mechanisms, and that no AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-119 addresses nickel alloy, PVC, and glass piping, piping components, and piping elements exposed to air with borated water leakage, uncontrolled indoor air, condensation, and waste water. The applicant stated that it is consistent with the GALL Report for glass components exposed to waste water, but that for other material and environment combinations encompassed by this item there are no components within the auxiliary systems that are within the scope of license renewal. SRP-LR Table 3.3-1, item 3.3.1-119 states that there are no aging effects, aging mechanisms, and that no AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

3.3.2.1.2 Loss of Material Due to 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, which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs to manage the aging effect for stainless steel and aluminum components. 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. GALL Report AMPs XI.M2 and XI.M32 recommend using water chemistry controls and a one-time visual or volumetric inspection to manage aging.

The staff's evaluations of the applicant's Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs are documented in SER Sections 3.0.3.1.41, 3.0.3.1.32, and 3.0.3.2.2, respectively. The staff noted that the Water Chemistry Control – BWR and One-Time Inspection Programs propose to manage the aging of stainless steel and aluminum components through the use of water chemistry controls and a one-time inspection using visual, ultrasonic, or surface techniques to ensure the effectiveness of the water chemistry control program. The staff also noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage aging through the use of periodic inspections, as least once every 5 years, using visual or other appropriate techniques. In its review of components associated with item 3.3.1-25, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry Control – BWR, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance Programs acceptable because the Water Chemistry Control – BWR Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection and Periodic Surveillance and Preventive Maintenance Programs include visual, ultrasonic, surface inspection, or other appropriate techniques capable of detecting pitting and crevice corrosion.

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).

3.3.2.1.3 Hardening and Loss of Strength Due to Elastomer Degradation; Loss of Material Due to Erosion

LRA Table 3.3.1, item 3.3.1-32.5, addresses elastomer seals and components exposed to raw water that will be managed for hardening and loss of strength due to elastomer degradation and loss of material due to erosion. For the AMR item that cites generic note E, the LRA credits the

Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage cracking and changes in material properties in elastomer components of the circulation water system. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M20 states that examinations of polymeric materials should be consistent with the examinations described in AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff notes that AMP XI.M38 monitors internal surfaces of elastomeric components for hardening, loss of strength, cracking, and loss of material due to wear.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. In its review of components associated with item 3.3.1-32.5, the applicant cited generic note E. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because this program also manages aging of elastomeric materials for hardening, loss of strength, and loss of material due to wear in raw water.

3.3.2.1.4 Gray Cast Iron Ejector Exposed to Raw Water

LRA Table 3.3.1, item 3.3.1-38 addresses steel heat exchanger components exposed to raw water that will be managed for managing loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion; and fouling. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed.

During its review of components associated with item 3.3.1-38, the staff noted that LRA Table 3.3.2-19-19 contains an AMR result for gray cast iron ejector internally exposed to raw water that will be managed for loss of material using the Service Water Integrity Program. Table IX.C of the GALL Report, Revision 2, defines steel as including gray cast iron, but cautions that gray cast iron is susceptible to selective leaching. However, loss of material due to selective leaching is not listed as an aging effect requiring management for the gray cast iron ejector. Therefore, by letter dated May 24, 2012, the staff issued RAI 3.3.2.19.-1 requesting that the applicant explain why the gray cast ejector exposed to raw water does not need to be managed for loss of material due to selective leaching.

In its response dated June 22, 2012, the applicant stated that LRA Table 3.3.2-19-19 should have included the Selective Leaching Program for the gray cast iron ejector exposed to raw water. The applicant revised LRA Table 3.3.2-19-19 to include gray cast iron ejector exposed to raw water to be managed by the Selective Leaching Program.

The staff finds the applicant's response acceptable because the applicant revised the LRA table to include loss of material due to selective leaching as an aging effect to be managed, which is consistent with the recommendations in the GALL Report. Therefore, the staff's concern described in RAI 3.3.2.19-1 is resolved.

3.3.2.1.5 Reduction of Heat Transfer Due to Fouling

LRA Table 3.3.1, item 3.3.1-42, addresses copper-alloy heat exchanger tubes exposed to raw water that will be managed for reduction of heat transfer due to fouling. For the AMR item that cites generic note E, the LRA credits the Fire Water System to manage the aging effects for reduction of heat transfer due to fouling. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M20 recommends using periodic performance testing or inspections to manage aging.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.1.20. The staff noted that the Fire Water System Program proposes to manage fouling of copper-alloy heat exchanger tubes in the fire protection – water system through the use of inspections and monitoring activities. In its review of components associated with item 3.3.1-42 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the inspections and monitoring activities performed in the program are capable of detecting fouling of the heat exchanger tubes.

3.3.2.1.6 Loss of Material Due to Microbiologically-Influenced Corrosion

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 that will be managed for loss of material due to microbiologically-influenced corrosion. The GALL Report recommends GALL Report AMP XI.M21A, "Closed Treated Water Systems" to ensure that these aging effects are adequately managed.

During its review of components associated with item 3.3.1-47 for which the applicant cited generic note C, the staff noted that the LRA credits the Water Chemistry Control – Closed Treated Water Systems Program to manage the aging effect for stainless steel heat exchanger tubes and tubesheets exposed to treated water. The staff also noted that the GALL Report (e.g., items V.D2.EP-93 and VIII.E.S-25) also recommends that stainless steel heat exchanger components be managed for loss of material due to pitting and crevice corrosion. The staff further noted, however, that the microbiologically-influenced corrosion inspection activities in the Water Chemistry Control – Closed Treated Water Systems Program are also capable of detecting loss of material due to pitting and crevice corrosion.

The staff's evaluation of the applicant's Water Chemistry Control – Closed Treated Water Systems Program is documented in SER Section 3.0.3.1.42. The staff finds the applicant's proposal to manage pitting corrosion, crevice corrosion, and microbiologically-influenced corrosion using the Water Chemistry Control – Closed Treated Water Systems Program acceptable because the water chemistry controls are capable of mitigating the environmental effects on loss of material due to pitting, crevice, and microbiologically-influenced corrosion and the opportunistic and periodic inspections can detect the presence or extent of corrosion before loss of intended function.

The staff concludes that for LRA item 3.3.1-47, 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 Copper Alloy with Greater than 15 Percent Zinc or 8 Percent Aluminum Strainers Exposed to Raw or Treated Water

LRA Table 3.3.1, item 3.3.1-72, addresses gray cast iron and copper alloy with greater than 15 percent zinc or 8 percent aluminum piping, piping components, and piping elements exposed to treated water, raw water, closed-cycle cooling water, or soil that will be managed for loss of material due to selective leaching. The GALL Report recommends GALL Report AMP XI.M33, “Selective Leaching,” to ensure that this aging effect is adequately managed.

During its review of components associated with item 3.3.1-72, the staff noted that LRA Table 3.3.2-12 contains AMR results for copper alloy with greater than 15 percent zinc or 8 percent aluminum strainers exposed internally and externally to raw water and treated water. The AMR items are being managed for loss of material due to selective leaching on the internal surfaces using the Selective Leaching Program. However, the AMR items are not being managed for loss of material due to selective leaching on the external surfaces. Therefore, by letter dated May 24, 2012, the staff issued RAI 3.3.1.72-1 requesting that the applicant explain why the external surfaces of the strainers do not need to be managed for loss of material due to selective leaching.

In its response dated June 22, 2012, the applicant revised LRA Table 3.3.2-12 to include loss of material due to selective leaching as an aging effect for the external surfaces of the strainers exposed to raw water and treated water. The applicant proposes to manage this aging effect with the Selective Leaching Program.

The staff finds the applicant’s response acceptable because the applicant will manage loss of material due to selective leaching for the copper-alloy strainers with greater than 15 percent zinc or 8 percent aluminum. This approach is consistent with the recommendations in the GALL Report. Therefore, the staff’s concern described in RAI 3.3.1.72-1 is resolved.

3.3.2.1.8 Copper Alloy with Greater than 15 percent Zinc or 8 percent Aluminum Components Exposed to Condensation

LRA Table 3.3.1, item 3.3.1-72 addresses gray cast iron and copper alloy with greater than 15 percent zinc or 8 percent aluminum piping, piping components, and piping elements exposed to treated water, raw water, closed-cycle cooling water, or soil that will be managed for loss of material due to selective leaching. The GALL Report recommends GALL Report AMP XI.M33, “Selective Leaching,” to ensure that this aging effect is adequately managed.

During its review of components associated with item 3.3.1-72, the staff noted that LRA Table 3.3.2-14 contains AMR results for copper alloy with greater than 15 percent zinc or 8 percent aluminum and gray cast iron valve bodies and gray cast iron pump casing externally exposed to condensation that will be managed for loss of material using the Selective Leaching Program. Additionally, LRA Table 3.3.2-19-6 contains an AMR item for gray cast iron valve body internally exposed to condensation that will be managed for loss of material using the Selective Leaching Program. However, LRA Tables 3.3.2-11, 3.3.2-16, 3.3.2-19-16, 3.3.2-19-19, 3.3.2-19-21, 3.3.2-19-26, 3.3.2-19-27, and 3.3.2-19-28 contain AMR results for copper alloy with greater than 15 percent zinc or 8 percent aluminum and/or gray cast iron valve bodies and piping internally or externally exposed to condensation, but loss of material due to selective leaching is not identified as an aging effect. Therefore, by letter dated May 24, 2012, the staff issued RAI 3.3.1.72-2 requesting that the applicant explain why the copper alloy with greater than 15 percent zinc or 8 percent aluminum and gray cast iron components exposed to condensation in the LRA tables identified above do not need to be managed for loss of material due to selective leaching.

In its response dated June 22, 2012, the applicant stated that copper alloy with greater than 15 percent zinc or 8 percent aluminum or gray cast iron components identified in LRA

Tables 3.3.2-11, 3.3.2-16, 3.3.2-19-21, 3.3.2-19-27, and 3.3.2-19-28 were conservatively assigned an internal environment of condensation and are part of compressed air systems. The applicant's justification stated that, since the compressed air systems are equipped with dryers that maintain an acceptably low dew point, the components are not subject to significant moisture that would allow selective leaching to occur.

The staff finds this portion of the applicant's response acceptable because the applicant clarified that the components in question are within compressed air systems and that it was conservative by assigning an environment of "condensation." The staff reviewed the applicant's UFSAR and confirmed that the instrument and plant air systems, and the standby diesel generator and HPCS diesel generator air start systems are equipped with air dryers designed to reduce the air dew point temperature to -40 °F at the designated pressure for the system. As such, there should not be significant pooling of moisture as to cause selective leaching.

The applicant also stated that copper alloy with greater than 15 percent zinc or 8 percent aluminum or gray cast iron components identified in LRA Tables 3.3.2-19-16, 3.3.2-19-19, and 3.3.2-19-26 were conservatively assigned an external environment of condensation, but are subject to only infrequent intermittent wetting. Therefore, the applicant concluded that loss of material due to selective leaching is not an aging effect requiring management for these components.

The staff finds this portion of the applicant's response acceptable because the applicant clarified that the components in question are subject to intermittent wetting. The presence of an electrolyte continuously is a key factor for selective leaching to initiate and propagate. The intermittent presence of electrolyte is expected to abate the selective leaching process. Additionally, the applicant selected AMR items from GALL Report (e.g., copper-alloy components externally exposed to condensation), and the recommended aging effect and AMP in the GALL Report are loss of material due to general, pitting, and crevice corrosion, and XI.M36, "External Surfaces Monitoring of Mechanical Components," respectively.

Lastly, the applicant stated that components identified in LRA Table 3.3.2-19-6 are conservatively identified as subject to condensation (internal) as part of the combustible gas control system. The applicant explained that the system normally operates only during quarterly testing, therefore, significant moisture will not be present and loss of material due to selective leaching is not an aging effect requiring management. The applicant stated it inadvertently applied the Selective Leaching Program to gray cast iron valves subject to internal condensation in LRA Table 3.3.2-19-6, but that it revised the table to delete the use of the Selective Leaching Program for gray cast iron valves subject to limited intermittent internal condensation.

The staff finds this portion of the response acceptable because, as explained above, the continuous presence of an electrolyte is a key factor for selective leaching to initiate and propagate, and its intermittent presence would abate the selective leaching process.

The staff's concern described in RAI 3.3.1.72-2 is resolved.

3.3.2.1.9 Loss of Material Due to General Corrosion

LRA Table 3.3.1, item 3.3.1-78 addresses steel piping, piping components, ducting, ducting components, and closure bolting exposed externally to air-indoor uncontrolled, air-outdoor, or condensation that will be managed for loss of material. LRA Table 3.3.1-81 addresses copper-alloy and aluminum piping, piping components, and piping elements exposed to air-outdoor that will be managed for loss of material. The GALL Report recommends GALL Report AMP XI.M36, “External Surface Monitoring of Mechanical Components,” to ensure that these aging effects are adequately managed. GALL Report AMP XI.M36 recommends using periodic visual inspections to manage loss of material for these components.

For the AMR items that cite generic note E in LRA Table 3.3.2-7, the LRA credits the Service Water Integrity Program to manage loss of material for carbon steel piping and copper-alloy nozzles exposed to air-outdoor (external) in the SSW system. The staff’s evaluation of the applicant’s Service Water Integrity Program is documented in SER Section 3.0.3.1.39. The staff noted that the Service Water Integrity Program proposes to manage the aging of steel piping and copper-alloy nozzles through the use of surveillance and control techniques, and inspections of critical components. In its review of components associated with item 3.3.1-78 and 3.3.1-81 for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage aging using the Service Water Integrity Program acceptable because the program includes visual inspections that are capable of identifying loss of material before loss of component intended function, which is consistent with the inspection method recommended in the GALL Report. For the AMR items that cite generic note E in LRA Table 3.3.2-13, the LRA credits the Fire Protection Program to manage loss of material for carbon steel and copper-alloy piping, tubing, and valve bodies, exposed to air-outdoor in the halon and CO_2 fire protection system. The staff’s evaluation of the applicant’s Fire Protection Program is documented in SER Section 3.0.3.1.19. The staff noted that the Fire Protection Program proposes to manage the aging of carbon steel and copper-alloy piping, valve bodies and tubing in the halon and CO_2 systems through the use of visual inspections. In its review of components associated with items 3.3.1-78 and 3.3.1-81 for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage aging using the Fire Protection Program acceptable because the program includes visual inspections that are capable of identifying loss of material before loss of component intended function, which is consistent with the inspection method recommended in the GALL Report.

As amended by letter dated May 13, 2014, for the AMR item that cites generic note E in LRA Table 3.3.2-12, the LRA credits the Fire Water System Program to manage loss of material for the fire water tank. Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02, which revised several AMPs, including the guidance for AMP XI.M27, “Fire Water System.” The revised AMP XI.M27 recommends that aging effects associated with fire water tanks be managed by AMP XI.M27 in lieu of AMP XI.M29. The staff’s evaluation of the applicant’s Fire Water System Program is documented in SER Section 3.0.3.1.20. In its review of components associated with item 3.3.1-78 for which the applicant cited generic note E in LRA Table 3.3.2-12, the staff finds the applicant’s proposal to manage aging using the Fire Water System Program acceptable because it is consistent with LR-ISG-2012-02.

The staff concludes that for LRA items 3.3.1-78 and 3.3.1-81, 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 Cracking Due to Stress Corrosion Cracking

LRA Table 3.3.1, item 3.3.1-83 addresses stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust that will be managed for cracking due to SCC. 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.

During its review of components associated with item 3.3.1-83 for which the applicant cited generic note A, the staff noted that the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for stainless steel expansion joints exposed to diesel exhaust in LRA Table 3.3.2-15; however, the LRA identifies other stainless steel piping, piping components, and piping elements exposed to diesel exhaust in LRA Table 3.3.2-16 that are not being managed for SCC. By letter dated May 24, 2012, the staff issued RAI 3.3.2.16-1 requesting that the applicant provide a technical basis for why the components in LRA Table 3.3.2-16 do not need to be managed for SCC.

In its response dated June 22, 2012, the applicant stated that the stainless steel expansion joint listed in LRA Table 3.3.2-16 is mounted in a horizontal position, which could promote pooling of condensation from diesel engine exhaust, and lead to cracking due to SCC. As a result, the applicant revised LRA Table 3.3.2-16 to add this potential aging effect. The applicant also stated that the vertically oriented stainless steel flexible connections listed in LRA Table 3.3.2-16 are not subject to pooling of condensation, and thus cracking due to SCC is not an aging effect requiring management. The applicant further stated that LRA Table 3.3.2-16 was revised to replace the stainless steel subcomponents with carbon steel subcomponents for the HPCS diesel generator turbocharger, after a review of new, more detailed vendor information revealed an earlier error in the LRA.

The staff finds the applicant's response acceptable because (1) stainless steel piping components exposed to diesel exhaust have been evaluated to determine their susceptibility to cracking due to SCC, (2) LRA Table 3.3.2-16 has been updated to correctly reflect the component material, and (3) stainless steel piping components exposed to diesel exhaust and that may be subject to cracking due to SCC have been identified and will be managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program, consistent with the GALL Report recommendations. The staff's concern described in RAI 3.3.2.16-1 is resolved.

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

LRA Table 3.3.1, item 3.3.1-88 addresses steel and stainless steel piping, piping components, piping elements, and tanks exposed to raw water (potable) or diesel exhaust, which will be managed for loss of material. 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 visual inspections performed during maintenance activities, surveillances, and scheduled outages to manage loss of material for metallic components. GALL Report AMP XI.M38 also recommends that the acceptance criteria for metallic components be that no abnormal surface conditions are present.

During its review of components associated with item 3.3.1-88, for which the applicant cited generic note C, the staff noted that the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for steel tanks exposed to treated water (internal) in LRA Table 3.3.2-19-24. However, the staff noted that corrosion may occur at inaccessible locations of metallic tanks supported on earthen or concrete foundations, such as the tank bottom. If the tanks are on earthen or concrete foundations, UT thickness measurements of the tank bottoms performed whenever the tank is drained, and at least once within 5 years of entering the period of extended operation should be included within the applicant's program. The Internal Surfaces in Miscellaneous Piping and Ducting Components Program does not state that thickness measurements of tank bottoms are included in the program. By letter dated May 24, 2012, the staff issued RAI 3.3.2.19-2 requesting that the applicant identify the type of foundation for the domestic water system tank, how it is mounted or supported, and the inspection technique that will be used to manage aging.

In its response dated June 22, 2012, the applicant stated that the domestic water system tank is an indoor tank in the control building that is supported on a pedestal and managed for loss of material externally by the External Surfaces Monitoring Program. The applicant also stated that the external surface of the tank, and its bottom portion, is age managed through visual inspections for evidence of loss of material. The staff finds the applicant's response acceptable because the external and internal portions of the tank are being managed for aging using the visual inspections associated with the External Surfaces Monitoring and the Internal Surfaces in Miscellaneous Piping and Ducting Components Programs, which is consistent with the GALL Report recommendations. The staff's concern described in RAI 3.3.2.19-2 is resolved.

The staff concludes that for LRA item 3.3.1-88, 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).

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

LRA Table 3.3.1, items 3.3.1-89 and 3.3.1-90 address steel and copper-alloy piping, piping components, and piping elements exposed to moist air or condensation (internal) and steel ducting components exposed to condensation, which will be managed for loss of material due to general, pitting, and crevice corrosion. Drip pans and drain lines also will be managed for loss of material due to microbiologically-influenced corrosion. For the AMR items that cite generic note E, the LRA credits the Fire Water System Program to manage the aging effects for carbon steel tanks and breather vents exposed internally to condensation in LRA Table 3.3.2-12. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M38 recommends using visual inspections performed during maintenance activities, surveillances, and scheduled outages to manage loss of material for metallic components. GALL Report AMP XI.M38 also recommends that the acceptance criteria for metallic components be that no abnormal surface conditions are present.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.1.20. The staff noted that the Fire Water System Program proposes to manage the aging of components in the fire protection system through the use of preventive, inspection, and monitoring activities, including monitoring of system pressure, system flow tests, flushes, and piping wall thickness evaluations. However, the staff noted that corrosion may occur at inaccessible locations of metallic tanks supported on earthen or concrete foundations, such as the tank bottom. The Fire Water System Program does not state that it includes thickness measurements of tank bottoms. By letter dated May 24, 2012, the staff issued RAI 3.3.2.19-2 requesting that the applicant identify how the fire water storage tanks are mounted or supported and the inspection technique that will be used to manage aging.

In its response dated June 22, 2012, the applicant stated that the tanks in question are the fire water storage tanks that are supported by soil and a concrete foundation ring. The applicant also stated that the exterior surfaces, including the tank bottoms, are managed by the Aboveground Metallic Tanks Program, which includes measurements of the tank bottom thicknesses. The applicant further stated that the soil environment was not included in the LRA, and revised LRA Table 3.3.2-12 to include an AMR item for the carbon steel tanks exposed to soil being managed for loss of material using the Aboveground Metallic Tanks Program. The staff finds the applicant's response acceptable because the inaccessible portions of the fire water storage tanks are being managed in other AMR items consistent with the GALL Report recommendations. The staff's concern described in RAI 3.3.2.19-2 is resolved.

In its review of components associated with items 3.3.1-89 and 3.3.1-90 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging for carbon steel components exposed internally to condensation using the Fire Water System Program acceptable because the program includes internal visual inspections or other non-intrusive wall thickness evaluations that are capable of detecting loss of material for this component group.

The staff concludes that for LRA items 3.3.1-89 and 3.3.1-90, 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 Due to General, Pitting, Crevice and Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-91, addresses steel piping, piping components, piping elements, and tanks exposed to waste water, which will be managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M38 recommends using visual inspections performed during maintenance activities, surveillances, and scheduled outages to manage the loss of material for metallic components. GALL Report AMP XI.M38 also recommends that the acceptance criteria for metallic components be that no abnormal surface conditions are present.

During its review of components associated with item 3.3.1-91, for which the applicant cited generic note C, the staff noted that the LRA credits the Internal Surfaces in the Miscellaneous Piping and Ducting Components Program to manage the aging effect for carbon steel tanks exposed to waste water in LRA Table 3.3.2-19-20. However, the staff noted that corrosion may occur at inaccessible locations of metallic tanks supported on earthen or concrete foundations, such as the tank bottom. If the tanks are on earthen or concrete foundations, UT thickness measurements of the tank bottoms performed whenever the tank is drained and at least once within 5 years of entering the period of extended operation should be included within the applicant's program. The Internal Surfaces in the Miscellaneous Piping and Ducting Components Program does not state that thickness measurements of tank bottoms are included in the program. By letter dated May 24, 2012, the staff issued RAI 3.3.2.19-2 requesting that the applicant identify the type of foundation for the tanks, how they are mounted or supported, and the inspection technique that will be used to manage aging.

In its response dated June 22, 2012, the applicant stated that these tanks are indoor tanks in the auxiliary and turbine building that are not exposed to wetted external conditions. The applicant also stated that the tank bottom is in contact with dry concrete, and therefore, there is no aging effect requiring management for the external surface of the tank bottoms. The staff noted that the GALL Report recommends that there be no aging effects requiring management for steel components exposed to dry concrete. The staff finds the applicant's response acceptable because the tank bottoms are not subject to an aging effect externally, and the tank internal surfaces will be managed for loss of material by the Internal Surfaces in the Miscellaneous Piping and Ducting Components Program, which is consistent with the GALL Report recommendations. The staff's concern described in RAI 3.3.2.19-2, for these tanks, is resolved.

By letter dated May 13, 2014, the applicant revised LRA Table 3.3.2-19-20, including item 3.3.1-91 associated with RAI 3.3.2.19-2. During an internal review, the applicant noted a discrepancy between the tank material identified in LRA Table 3.3.2-19-20 and the actual material used to fabricate the tank. LRA Table 3.3.2-19-20 included table entries for tanks constructed from carbon steel (material). All tanks subject to aging management review applicable to LRA Table 3.3.2-19-20 are constructed from stainless steel. The correction of this error has resulted in item 3.3.1-91, identified in RAI 3.3.2.19-2, being changed to item 3.3.1-95. The technical basis for the issuance of RAI 3.3.2.19-2 and the applicant's response both remain valid. The staff's concern described in RAI 3.3.2.19-2, for these tanks, is resolved.

LRA Table 3.3.1, items 3.3.1-91 addresses steel piping, piping components, piping elements, and tanks exposed to waste water, which will be managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion. For the AMR items that cite generic note E, the LRA credits the Periodic Surveillance and Preventive Maintenance Program to manage the aging effect for carbon steel drain housing, piping, and valve bodies. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M38 recommends using visual inspections performed during maintenance activities, surveillances, and scheduled outages to manage loss of material for metallic components. GALL Report AMP XI.M38 also recommends that the acceptance criteria for metallic components be that no abnormal surface conditions are present.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.2.2. The staff noted that the Periodic Surveillance and Preventive Maintenance Program is a new plant-specific program that proposes to manage the aging of carbon steel drain housing, piping, and valve bodies through the use of visual inspections or other NDE techniques for the piping and visual inspections for the drain housing and valve bodies. The staff also noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage aging with inspections performed during preventative maintenance activities and periodic surveillances, with each inspection to occur at least once every 5 years. In its review of components associated with item 3.3.1-91, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable, because the program includes inspection techniques that are capable of detecting the loss of material from metallic components prior to the loss of the component intended function, which is consistent with the GALL Report recommendations.

The staff concludes that for LRA item 3.3.1-91, 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 Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-92 addresses aluminum piping, piping components, and piping elements exposed to condensation. The GALL Report recommends GALL Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” to manage loss of material due to pitting and crevice corrosion for this component group. The applicant stated that this item is applicable and consistent with the GALL Report; however, the staff noted that there are no Table 2 items that credit item 3.3.1-92. The lack of a Table 2 item indicates that the MEA combination is not applicable at the site, contradicting the information provided in LRA item 3.3.1-92. By letter dated May 24, 2012, the staff issued RAI 3.3.1.92-1 requesting that the applicant update the LRA to identify appropriate Table 2 items, or provide technical justification for why the item is not applicable.

In its response dated June 22, 2012, the applicant stated that LRA Tables 3.3.2-15 and 3.3.2-16 include one aluminum component type internally exposed to condensation, which is managed by the Compressed Air Monitoring Program for loss of material. The applicant revised LRA Table 3.3.1, item 3.3.1-92 to identify that the Compressed Air Monitoring Program will be used to manage loss of material for this component group. The applicant revised the aluminum components exposed internally to condensation in LRA Tables 3.3.2-15 and 3.3.2-16 to identify the corresponding link to Table 3.3.1, item 3.3.1-92, citing generic note E.

The staff finds the applicant’s response acceptable because the applicant has identified appropriate AMR items in Tables 3.3.2-15 and 3.3.2-16 that reference item 3.3.1-92. The staff’s concern described in RAI 3.3.1.92-1 is resolved.

The staff’s evaluation of the applicant’s Compressed Air Monitoring Program is documented in SER Section 3.0.3.1.11. The Compressed Air Monitoring Program consists of air quality monitoring and inspection of component internal surfaces to manage loss of material for components in compressed air systems. In its review of components associated with item 3.3.1-92 for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage aging using the Compressed Air Monitoring Program acceptable because the program will use internal surface inspections to detect a loss of material, which is consistent with the inspection method recommended in the GALL Report for aluminum components exposed to condensation.

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).

3.3.2.1.15 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-95 addresses copper-alloy, stainless steel, nickel alloy, and steel piping, piping components, piping elements, heat exchangers, and tanks exposed to waste water (external), which will be managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion. For the AMR items that cite generic note E, the LRA credits the Periodic Surveillance and Preventive Maintenance Program to manage the aging effect for stainless steel piping in the floor and equipment drains system. The GALL Report recommends GALL Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” to ensure that this aging effect is adequately managed.

GALL Report AMP XI.M38 recommends using visual inspections performed during maintenance activities, surveillances, and scheduled outages to manage loss of material for metallic components. GALL Report AMP XI.M38 also recommends that the acceptance criteria for metallic components be that no abnormal surface conditions are present.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.2.2. The staff noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage the aging of stainless steel piping through the use of visual inspections or other NDE techniques. The staff also noted that the Periodic Surveillance and Preventive Maintenance Program proposed to manage aging with inspections held during preventive maintenance activities and periodic surveillances, with each inspection to occur at least once every 5 years. The staff also noted that inspections using NDE techniques are as effective at identifying loss of material in stainless steel floor and equipment drain system piping as visual inspections. In its review of components associated with item 3.3.1-95, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because the program includes inspection techniques that are capable of identifying loss of material in stainless steel piping before loss of component intended function.

The staff concludes that for LRA item 3.3.1-95, 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 Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-97, addresses steel piping, piping components, and piping elements and steel reactor coolant pump oil collection system components exposed to lubricating oil that will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect carbon steel filters and filter housing exposed to lubricating oil. The GALL Report recommends GALL Report AMP XI.M39, "Lubricating Oil Analysis," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M39 recommends performing periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with industry standards to manage aging.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff noted that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of carbon steel filters, filter housing, and fan housing through the use of visual inspections. In its review of components associated with items 3.3.1-97 and 3.4.1-40 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because visual inspections will ensure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

The staff concludes that for LRA item 3.3.1-97, 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).

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

LRA Table 3.3.1, item 3.3.1-67 addresses steel tanks exposed to air – outdoor (external), which will be managed for loss of material due to general, pitting, and crevice corrosion. As amended by letter dated May 13, 2014, for the AMR item that cites generic note E, the LRA credits the Fire Water System Program to manage the aging effect for the fire water tank. 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 examinations to manage aging.

Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02, which revised several AMPs, including the guidance for AMP XI.M27, "Fire Water System." The revised AMP XI.M27 recommends that aging effects associated with fire water tanks be managed by AMP XI.M27 in lieu of AMP XI.M29. The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.1.20. 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 Fire Water System Program acceptable, because it is consistent with LR-ISG-2012-02.

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).

3.3.2.1.18 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-64 addresses steel and copper alloy piping, piping components, piping elements, and tanks exposed to raw water, which will be managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion. For the AMR items that cite generic note E, the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for carbon steel and copper alloy filter housings, nozzles, piping, strainer housings, and valve bodies. The GALL Report recommends GALL Report AMP XI.M27, "Fire Water System," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M27 recommends using the applicable NFPA codes and standards to manage loss of material for metallic components, which include visual inspections, non-destructive wall thickness measurements, and flow testing.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff noted that the applicant included the updated guidance for this program from LR-ISG-2012-02. 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 the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the components are outside the scope of the Fire Water System Program, and the program includes inspection techniques capable of detecting loss of material from metallic components before the loss of component intended function.

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).

3.3.2.1.19 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed are not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed are not applicable are not applicable to GGNS.

As discussed in SER Section 3.3.2.1, 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 due to SCC and cyclic loading
- cracking due to SCC
- loss of material due to cladding breach
- loss of material due to pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant stated 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 air-indoor uncontrolled (external), and steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water, or treated water are being managed for cumulative fatigue damage.

The applicant stated that item 3.3.1-1 was not used. Steel cranes are evaluated as structural components in LRA Section 3.5.1. The staff noted that potential TLAAs identified for cranes are discussed in LRA Section 3.5.2.3. Furthermore, in LRA Table 4.1-2, the applicant identified that the CLB does not include any analysis for the polar crane that would need to be identified as a TLAA in the LRA. By letters dated June 5 and September 7, 2012, the staff issued RAIs 4.1-2 and 4.1-2a, requesting the applicant clarify why the time-dependent cycle analyses for the cranes would not need to be identified as TLAAs for the LRA, when assessed against the six criteria for identifying TLAAs in 10 CFR 54.3(a). The applicant responded to RAI 4.1-2a by letter dated October 2, 2012. In its response, the applicant resolved the request by amending the LRA to include a TLAA for the analyses for the spent fuel cask crane, new fuel handling crane and polar cranes. The details of RAI 4.1-2 and RAI 4.1-2a and the staff's evaluation of the applicant's response are documented in SER Section 4.1.2.1.2.7. As part of the response, the applicant amended AMR item 3.3.1-1 to identify that the analysis of fatigue for steel crane structural girders is a TLAA. 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 evaluation of crane load cycles as a TLAA is discussed in LRA Section 4.7.4.

The applicant addressed, for item 3.3.1-2, the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and 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.

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 Section 4.3. The staff also reviewed the AMR 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, except as identified below.

The staff identified that the applicant did not include the applicable AMR items in LRA Tables 3.3 for the TLAAs associated with fatigue of non-Class 1. The staff noted that LRA Section 4.3.2 discusses the TLAAs associated with fatigue of non-Class 1 piping and states that these TLAAs will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). Therefore as part of the RAI 3.2.2-1, the staff requested the applicant justify this discrepancy. The details of RAI 3.2.2-1 and the staff's evaluation of the applicant's response are documented in SER Section 3.2.2.2.1.

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 4.7 document the staff's review of the applicant's evaluation of the TLAA for these components.

3.3.2.2.2 Cracking Due to 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 Due to Stress Corrosion Cracking

LRA Section 3.3.2.2.3, which is associated with LRA Table 3.3.1, item 3.3.1-4, addresses stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor that will be managed for cracking due to SCC. The applicant stated that this item is not applicable because there are no in-scope stainless steel components exposed to outdoor air or located near unducted air intakes in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and the UFSAR and finds that no in-scope stainless steel piping, piping components, piping elements and tanks exposed to air-outdoor are present in the auxiliary systems.

3.3.2.2.4 Loss of Material Due to 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 due to 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 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.

3.3.2.2.5 Loss of Material Due to Pitting and Crevice Corrosion

LRA Section 3.3.2.2.5, which is associated with LRA Table 3.3.1, item 3.3.1-6, addresses stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor that will be managed for loss of material due to pitting and crevice corrosion. The applicant stated that this item is not applicable because there are no in-scope stainless steel components exposed to outdoor air or located near unducted air intakes in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and the UFSAR and finds that no in-scope stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor are present in the auxiliary systems.

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.

3.3.2.2.7 Loss of Material Due to Recurring Internal Corrosion

By letter dated May 13, 2014, the applicant addressed recurring internal corrosion that is described in Section A and Appendix B of LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation." LR-ISG-2012-02 includes a new section (Section 3.3.2.2.8, Loss of Material Due to Recurring Internal Corrosion) in the SRP-LR for "AMR Results for Which Further Evaluation Is Recommended by the GALL Report." This section of the SER documents the staff's evaluation of the applicant's activities to address recurring internal corrosion, as described in SRP-LR Section 3.3.2.2.8 from LR-ISG-2012-02.

Based on its review of plant-specific operating experience for the past 5 years, the applicant stated that microbiologically-influenced corrosion of piping components is a recurring internal corrosion issue, as defined in LR-ISG-2012-02, Section A. The applicant further stated that it monitors loss of material in piping components due to microbiologically-influenced corrosion in four systems: CW, SSW, plant service water, and fire protection.

The applicant stated that it monitors selected locations using UT and radiographic testing techniques to determine wall thickness. The selected locations provide a representative sample of the piping systems and are chosen based on configuration, flow conditions, and operating history. Locations can be added or deleted as new information becomes available. The applicant stated that, in the past 5 years, 60 inspections have been performed, and a minimum of 5 inspections per refueling cycle will be performed until microbiologically-influenced corrosion no longer meets the criteria for recurring internal corrosion. The applicant determines corrosion rates by comparing the measured wall thickness to the nominal thickness, or to previous thickness measurements, and determines when to perform subsequent measurements or to replace components, based on the corrosion rate and the estimated time to reach the ASME Code minimum wall thickness plus a thickness margin. In addition, the applicant considers multiple corrosion locations when determining structural integrity of the piping.

The applicant also stated that the current degradation monitoring has been effective in identifying internal pipe corrosion, and pipe wall thinning has not resulted in the loss of a component's ability to support system pressure and flow requirements. Also, leakage caused by microbiologically-influenced corrosion onto nearby equipment has not resulted in the loss of any safety functions. For the buried portions of affected systems, the applicant will select an inspection method prior to the period of extended operation that provides a suitable indication of pipe wall thickness for a representative sample to supplement the existing inspection locations. The applicant further stated that underground leaks are detectable by changes in system performance, changes in system operation, or by the appearance of wetted ground, and leaks large enough to affect the function of systems are expected to develop slowly, due to the slow progression of pin-hole leaks from microbiologically-influenced corrosion. The applicant augmented the Periodic Surveillance and Preventive Maintenance Program to incorporate the above described monitoring activities associated with recurring internal corrosion and revised LRA Sections A.1.35 and B.1.35, and the tables in LRA Sections 3.3 and 3.4 to account for the changes.

During its review of the applicant's information, it was unclear to the staff whether the augmented program would perform inspections of five locations in each of the four systems that had been identified or just five locations in all these systems as a collective population of components. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-RIC-1, part 2, requesting that the applicant clarify this issue. In its response dated November 6, 2014, the applicant stated that the number of inspections implemented by the Periodic Surveillance and Preventive Maintenance Program is based on the previous evaluations, the calculated remaining service life of components in the systems, and the previous selected areas of concern. The applicant stated that 16 inspections are scheduled for the next cycle; however; the number of inspections could change depending on the evaluation of the current cycle inspection results. The applicant clarified that a minimum of 5 inspections in the collective set of systems will be performed per cycle and that this minimum rate of 5 inspections per cycle will result in 25 inspections in a 10-year period.

The staff notes that LR-ISG-2012-02, Section B, recommends that a minimum of 20 percent for each population of in-scope components, with a maximum sample size of 25, be performed for inspections that are conducted in accordance with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff also notes that

LR-ISG-2012-02 defines the population of components for inspection as those components that are subject to the same material, environment, and aging effect combination, and states that, where practical, inspection locations are selected from bounding or lead components (e.g., low or stagnant flow) most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin. Thus, the staff found that the applicant had provided an acceptable minimum sample-size basis for performing inspections of the four susceptible systems under the Periodic Surveillance and Preventive Maintenance Program, because the staff has verified that this inspection basis is in conformance with the recommendations in Section B of LR-ISG-2012-02 for similar sampling-based programs, such as that for GALL Report AMP XI.M38. The staff's concern described in RAI 3.0.3-1-RIC-1, part 2 is resolved.

Also during its review of the applicant's information, the staff noted that the applicant's bases for selecting inspection locations include piping configurations, flow conditions, and operating history and provide a representative sample of the piping system. The staff compared this to the recommendations in SRP-LR Section A.1.2.3.4, which states that samples should be biased towards locations most susceptible to the specific aging effect of concern. It was unclear to the staff how the specified sample selection criteria will be biased toward components that are most susceptible to microbiologically-influenced corrosion. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-RIC-1, part 3, requesting that the applicant clarify this issue.

In its response dated November 6, 2014, the applicant stated that component selections are biased toward locations most susceptible to microbiologically-influenced corrosion and consider a number of characteristics that cause components to be conducive to microbiologically-influenced corrosion. The applicant also stated that implementing procedures will be revised to clearly state that the most susceptible locations are selected for inspection and that it amended LRA Sections A.1.35 and B.1.35 to reflect this approach. The staff finds the applicant's response to be acceptable, because the sample selection criteria for the Period Surveillance and Preventive Maintenance Program are consistent with the sample selection criteria in SRP-LR Section A.1.2.3.4. The staff's concern described in RAI 3.0.3-1-RIC-1, part 3 is resolved.

Also during its review of the applicant's information, the staff noted that the applicant changed LRA Sections A.1.35 and B.1.35 by stating that inspections for recurring internal corrosion would use UT or other nondestructive wall thickness measurements of the components that are selected for inspection. However, the staff noted that the applicant did not define or justify the type of NDE method that would be applied as the inspection technique if UT is not used. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-RIC-1, part 4, requesting that the applicant clarify and justify the alternative inspection method if UT is not used for the inspections.

In its response dated November 6, 2014, the applicant revised LRA Sections A.1.35 and B.1.35 to specify that UT or radiographic testing will be used for inspecting for loss of material due to microbiologically-influenced corrosion. The applicant stated that radiographic testing can be used for those configurations where UT is not effective, such as small-bore piping with socket welded fittings. The staff finds this response acceptable, because radiographic testing is an accepted volumetric NDE method capable of detecting loss of material. The staff's concern described in RAI 3.0.3-1-RIC-1, part 4, is resolved.

Also during its review of the applicant's information, the staff noted that the applicant had not provided any provisions for expanding the sample size or for identifying the inspection expansion criteria that will be applied if further corrosion is detected as a result of implementing the augmented inspections. By letter dated September 11, 2014, the staff issued RAI 3.0.3-1-RIC-1, part 5, requesting that the applicant identify and justify the component inspection sample expansion criteria that will be applied to the systems, if further evidence of microbiologically-influenced corrosion or other corrosion effects is detected in these systems.

In its response dated November 6, 2014, the applicant stated that the scope of the examinations will be expanded if substantial microbiologically-influenced corrosion is detected during inspections. The applicant stated that scope expansion includes consideration of other locations for additional sampling, such as similar components in the same or redundant trains. The applicant clarified that it considers microbiologically-influenced corrosion to be substantial if there is either an increased rate of detection of new microbiologically-influenced corrosion sites, increased rates of wall thinning at known sites, or unexpected piping wall loss that results in a component wall thickness near or below the minimum wall thickness required by the design code for the component. The staff finds that the applicant's response acceptable, because it provided adequate bases for expanding the sample size. The staff's concern described in RAI 3.0.3-1-RIC-1, part 5 is resolved.

Based on the changes and clarifications provided above, the staff determines that the applicant's Periodic Surveillance and Preventive Maintenance Program meets the criteria in SRP-LR Section 3.3.2.2.8, as modified by LR-ISG-2012-02. 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).

3.3.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

For LRA Tables 3.3.2-1 through 3.3.2-19, 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 3.3.2-19, 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.

3.3.2.3.1 Control Rod Drive – 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 CRD component groups.

In LRA Table 3.3.2-1, the applicant stated there are TLAAs for stainless steel tubing, and valve body exposed to steam, which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

<u>Carbon Steel Piping Components Exposed to Treated Water</u>. By letter dated December 18, 2012, and as modified by letter dated December 20, 2013, the applicant revised LRA Tables 3.3.2-1, 3.3.2-6, 3.3.2-19-1, 3.3.2-19-8, and 3.3.2-19-20, and stated that carbon steel piping components exposed to treated water will be managed for loss of material by the Flow-Accelerated Corrosion Program. The AMR items cite generic note H and also cite plant-specific note 309, which states that the aging effect used for this item refers to loss of material due to erosion.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel piping components exposed to treated water are susceptible to loss of material due to general, pitting, crevice, and flow-accelerated corrosion and recommends GALL Report AMP XI.M2, AMP XI.M32, and AMP XI.M17 to manage the aging effect due to these mechanisms. However the applicant has identified additional aging mechanisms. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in other AMR items in LRA Tables 3.3.2-1, 3.3.2-6, 3.3.2-19-1, 3.3.2-19-8, and 3.3.2-19-20.

The staff's evaluation of the applicant's Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.1.21. The staff finds the applicant's proposal to manage loss of material due to erosion mechanisms using the Flow-Accelerated Corrosion Program acceptable, because the associated components can be treated similar to "susceptible-not-modeled" components currently within the program, which ensures that the consequent wall thinning will be detected before loss of intended function.

3.3.2.3.2 Standby Liquid Control – 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 SLC component groups.

<u>Nickel Alloy Expansion Joint Exposed to Sodium Pentaborate</u>. In LRA Table 3.3.2-2, the applicant stated that the nickel alloy expansion joints exposed to sodium pentaborate will be managed by for loss of material by the Water Chemistry Control – BWR 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, based on the UFSAR, the components in the SLC system do not exceed 100 °F, which indicates that cracking is not an aging effect requiring management. The staff also noted that the Metals Handbook, Desk Edition, Second Edition (ASM International, 1998) states that nickel and nickel-base alloys generally have very good corrosion resistance in distilled and fresh waters, and the ASM Handbook, Volume 13B, “Corrosion of Nickel and Nickel-Based Alloys” chapter (ASM International, 2005) states that nickel alloys are subject to SCC only in specific environments, such as hot caustic, fluoride, and chloride-containing water environments. Based on this review, 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 applicant’s Water Chemistry Control – BWR Program is documented in SER Section 3.0.3.1.41. The staff finds the applicant’s proposal to manage aging using this program acceptable because the Water Chemistry Control – BWR Program controls contaminants in the makeup water to the SLC system at levels to minimize loss of material.

In LRA Table 3.3.2-2, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for nickel alloy expansion joints exposed to sodium pentaborate solution which cite generic note G. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.2.2 for this component and material. The staff’s evaluation of the fatigue TLAA for non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

<u>Stainless Steel Expansion Joint Exposed to Sodium Pentaborate</u>. In LRA Table 3.3.2-2, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for stainless steel expansion joints exposed to sodium pentaborate solution which cite generic note H. The staff confirmed that there is a TLAA as documented in LRA Section 4.3.2.2 for this component and material. The staff’s evaluation of the fatigue TLAA for non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

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).

3.3.2.3.3 Suppression Pool Makeup - 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 suppression pool makeup 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.

3.3.2.3.4 Leakage Detection and Control – 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 leakage detection and control component groups.

<u>Stainless Steel Components, Piping, and Valves Exposed to Steam</u>. In LRA Table 3.3.2-4, the applicant that stated there are TLAAs for stainless steel piping, tubing, and valve body exposed to steam, which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

Stainless Steel Expansion Joints Exposed to Condensation. In LRA Table 3.3.2-4, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for stainless steel expansion joints exposed to condensation which cite generic note H. The staff confirmed that there is a TLAA as documented in LRA Section 4.3.2.2 for this component and material. The staff's evaluation of the fatigue TLAA for Non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

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).

3.3.2.3.5 Combustible Gas Control – 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 combustible gas control component groups.

Stainless Steel Tubing Exposed to Indoor Air. In LRA Table 3.3.2-5, the applicant stated there are TLAAs for stainless steel tubing exposed to air-indoor (internal) and stainless steel tubing exposed to air-indoor (external), which cite 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 non-Class 1 components is documented in SER Section 4.3.2.

Copper-alloy Heat Exchanger Tubes Exposed to Condensation (Internal). In LRA Table 3.3.2-5, the applicant stated that copper-alloy heat exchanger tubes exposed to condensation (internal) will be managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that copper-alloy piping, piping components, and piping elements exposed to condensation (internal) are susceptible to loss of material due to general, pitting, and crevice corrosion and recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage the aging effect. However, the applicant has identified the additional aging effect of fouling. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-5.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because it includes visual inspections of metallic components, which are capable of detecting fouling before loss of component intended function.

Stainless Steel Tubing Exposed to Lubricating Oil. In LRA Tables 3.3.2-5, the applicant stated that stainless steel tubing exposed to lubricating oil will be managed for cracking by the Oil

Analysis Program. The AMR items cite generic note H. The staff notes that this material and environment combination is identified in the GALL Report but for a different aging effect, stating that stainless steel tubing exposed to lubricating oil is susceptible to loss of material and recommending that the Lubricating Oil Analysis Program be used to manage the aging effect.

The staff's evaluation of the applicant's Oil Analysis Program is documented in SER Section 3.0.3.1.31. Note: The aging mechanisms that cause cracking in the lubricating oil environment are SCC and IGA. A corrosive environment (e.g., water) and a susceptible material must be present for these aging mechanisms to occur. The components stated above may consist of susceptible material (austenitic stainless steel) and when subjected to a caustic environment, SSC and IGA are possible. The Oil Analysis Program described in LRA Section B.1.28 manages the oil environments through periodic sampling and analysis so that water content may be maintained at a level that precludes a corrosive environment and thereby manages cracking of stainless steel. The staff finds the applicant's proposal to manage cracking using the Oil Analysis Program acceptable, because the Oil Analysis Program requires periodic sampling and testing of lubricating oil to ensure that contaminants (primarily water and particulates) are within acceptable limits.

<u>Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil</u>. As amended by letter dated May 13, 2014, in LRA Tables 3.3.2-5, 3.3.2-7, 3.3.2-9, 3.3.2-12, 3.3.2-14, 3.3.2-15, 3.3.2-16, 3.3.2-17, 3.3.2-19-7, 3.3.2-19-9, 3.3.2-19-16, 3.3.2-19-17, 3.3.2-19-18, 3.3.2-19-23, 3.3.2-19-24, 3.3.2-19-25, 3.3.2-19-26, and 3.3.2-19-27, the applicant stated that metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs. The new AMR items cite generic note H, indicating that this aging effect for the component, material, and environment combination is not included in the GALL Report.

Based on its reviews of LRAs and industry operating experience, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. As a result, the staff issued RAI 3.0.3-2 on January 2, 2014, requesting that the applicant address loss of coating integrity for Service Level III and other coatings. In its response dated May 13, 2014, the applicant stated that it had identified components where coating degradation has the potential to adversely affect the passive functions of downstream components, which is an aging effect not addressed in the GALL Report.

The staff's evaluation of the applicant's use of the Periodic Surveillance and Preventive Maintenance and Service Water Integrity Programs to manage loss of coating integrity is documented in SER Section 3.0.3.3. The staff noted that the applicant will make a number of enhancements to the programs to address loss of coating integrity, including internal visual inspections of the coated components. The staff finds the applicant's proposal to manage loss of coating integrity using the above programs acceptable, because the Periodic Surveillance and Preventive Maintenance and Service Water Integrity Programs will include periodic visual inspections by appropriately certified individuals, with specified acceptance criteria, and evaluations of inspection findings will be conducted by an appropriately qualified nuclear coatings subject matter expert, which will ensure that degradation of coating integrity is detected before causing a loss of intended function.

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).

3.3.2.3.6 Fuel Pool Cooling and Cleanup – 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 Fuel Pool Cooling and Cleanup component groups.

Carbon Steel Piping Components Exposed to Treated Water. The staff's evaluation for carbon steel piping components exposed to treated water, which will be managed for loss of material due to erosion mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.3.2.3.1.

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).

3.3.2.3.7 Standby Service Water – 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 SSW component groups.

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. The staff's evaluation for stainless steel piping, piping elements, and piping components externally exposed to condensation that will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note G, is documented in SER Section 3.2.2.3.7.

Carbon and Stainless Steel Closure Bolting Exposed to Condensation. In LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-14, 3.3.2-19-16, and 3.3.2-19-26 the applicant stated that the carbon and stainless steel closure bolting exposed to condensation will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon and stainless steel closure bolting exposed to condensation is susceptible to loss of material and recommends GALL Report AMP XI.M18 to manage the aging effect. However the applicant has identified an additional aging effect. The applicant addressed the GALL Report, which identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-14, 3.3.2-19-16, and 3.3.2-19-26.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.2. The staff finds the applicant's proposal to manage loss of preload using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload;

and inspects bolted connections for leakage to ensure detection of leakage occurs before the leakage becomes excessive.

Stainless Steel Piping Exposed to Soil. As amended by the 2012 Annual Update letter dated August 15, 2012, LRA Table 3.3.2-7 states that stainless steel piping exposed to soil will be managed for loss of material by the Buried Piping and Tanks Inspection program. The AMR item cites generic note G.

The staff noted that while the applicant cited generic note G, GALL Report item AP-56 states that stainless steel piping exposed to soil should be managed for loss of material by AMP XI.M41, "Buried and Underground Piping and Tanks."

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection program is documented in SER Section 3.0.3.1.4. The staff finds the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection program acceptable because periodic excavated direct visual examinations are capable of detecting loss of material and the applicant has committed to conduct soil sampling to determine if the soil is corrosive to stainless steel piping.

Stainless Steel Flexible Connections Exposed to Raw Water (Internal). In LRA Table 3.3.2-7, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for stainless steel flexible connections exposed to raw water (int) which cite generic note H. The staff confirmed that there is a TLAA as documented in LRA Section 4.3.2.2 for this component and material. The staff's evaluation of the fatigue TLAA for Non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

Carbon Steel and Stainless Steel Piping Components Exposed to Raw Water. As modified by letter dated May 13, 2014, LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-12, 3.3.2-19-16, 3.3.2-19-19, and 3.3.2-19-23 state that carbon steel and stainless steel piping components exposed to raw water will be managed for recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel and stainless steel piping components exposed to raw water are susceptible to loss of material, and, depending on the system, recommends several different AMPs for managing aging. However the applicant has identified recurring internal corrosion as an additional aging effect requiring management, as described in LR-ISG-2012-02. The applicant addressed the aging effects identified in the GALL Report for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-12, 3.3.2-19-16, 2.2.2-19-19, and 3.3.2-19-23.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.2.2. The staff finds the applicant's proposal to manage recurring internal corrosion using this program acceptable as documented in SER Section 3.3.2.2.7.

Insulated Carbon Steel, Stainless Steel and Copper Alloy Piping and Piping Components Exposed to External Condensation. As modified by letters dated May 13, 2014, and November 6, 2014, LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-14, 3.3.2-17, 3.3.2-19-14, 3.3.2-19-15, 3.3.2-19-16, 3.3.2-19-19, and 3.3.2-19-26 state that insulated carbon steel and stainless steel piping and piping components exposed to external condensation will be managed for loss of material by the External Surfaces Monitoring Program. In addition, as modified by letters dated

May 13, 2014, and November 6, 2014, LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-14, 3.3.2-17, 3.3.2-19-14, 3.3.2-19-15, and 3.3.2-19-19 state that insulated stainless steel and copper alloy piping and pipe components exposed to external condensation will be managed for cracking by the External Surfaces Monitoring Program. The AMR items cite generic note H and include a plant-specific note stating that the program provisions apply for indoor insulated components operating below the dew point.

The staff noted that this material and environment combination is not identified for insulated piping components in the GALL Report. However corrosion under insulation is addressed in LR-ISG-2012-02, Section E, and the applicant addressed this aspect in its response dated May 13, 2014, to the staff's RAI 3.0.3-1. The staff also noted that the applicant appropriately addressed the aging effects identified in the GALL Report for noninsulated components for this material and environment combination in other AMR items in LRA Tables 3.3.2-7, 3.3.2-9, 3.3.2-14, 3.3.2-17, 3.3.2-19-14, 3.3.2-19-15, 3.3.2-19-16, 3.3.2-19-19, and 3.3.2-19-26.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's proposal to use this program to manage loss of material for insulated carbon steel and stainless steel components exposed to an external condensation environment and cracking for stainless steel and copper alloy components exposed to an external condensation environment acceptable, because it is consistent with the staff recommendations for managing the loss of material that results from a "corrosion under insulation" aging mechanism, as established in Section E(iii)(b) of LR-ISG-2012-02 for insulated piping components.

<u>Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil.</u> The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

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 Component Cooling Water – 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 component cooling water 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.

3.3.2.3.9 Plant Service Water – 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 plant service water component groups.

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. The staff's evaluation for stainless steel piping, piping elements, and piping components externally exposed to condensation which will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note G, is documented in SER Section 3.2.2.3.7.

Carbon and Stainless Steel Closure Bolting Exposed to Condensation. The staff's evaluation for carbon and stainless steel closure bolting exposed to condensation that will be managed for loss of preload by the Bolting Integrity Program and cite generic note H, is documented in SER Section 3.3.2.3.7.

Carbon Steel and Stainless Steel Piping Components Exposed to Raw Water. The staff's evaluation for carbon steel and stainless steel piping components exposed to raw water, which will be managed for loss of material due to recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program and are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Insulated, Carbon Steel and Stainless Steel Piping and Piping Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel and stainless steel piping and piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

Plastic Sight Glasses Exposed to External Condensation. By letter dated October 25, 2013, the applicant amended LRA Table 3.3.2-9 to include plastic sight glasses exposed to external condensation, which will be managed for change in material properties by the External Surfaces Monitoring Program. The AMR items cite generic note F.

The staff noted that NUREG-1801 does not address change in material properties and cracking of plastic sight glass with an internal environment of raw water and an external environment of condensation. The staff reviewed the associated item 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 combination. The staff noted that, for a condensation environment, the behavior of plastic materials would be similar to elastomeric materials. Based on its review of GALL Report Section IX.C, "Selected Definitions & Use of Terms for Describing and Standardizing, Materials," which states that elastomeric materials are susceptible to hardening and loss of strength (change in material properties), 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 applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable, because the AMP includes periodic visual inspections that are capable of detecting a change in material properties (e.g., change in clarity, cracking, crazing, dimensional changes) prior to a loss of component intended function.

Plastic Sight Glasses Exposed to Raw Water (internal). As amended by letter dated October 25, 2013, the applicant revised LRA Table 3.3.2-9 to include plastic sight glasses exposed to raw water (internal), which will be managed for a change in material properties and cracking by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note F.

The staff noted that NUREG-1801 does not address change in material properties and cracking of plastic sight glass with an internal environment of raw water and an external environment of condensation. 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 combination. The staff noted that, for a raw water environment, the behavior of plastic materials would be similar to elastomeric materials. Based on its review of GALL Report Section IX.C, "Selected Definitions & Use of Terms for Describing and Standardizing, Materials," which states that elastomeric materials are susceptible to hardening and loss of strength (change in material properties), 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 applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable, because the program includes periodic visual inspections that are capable of detecting cracking and change in material properties (e.g., change in clarity, cracking, crazing) prior to a loss of component intended function.

Stainless Steel Exposed to Condensation. By letter dated October 25, 2013, the applicant amended LRA Table 3.3.2-9 to include stainless steel exposed to external condensation, which will be managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated item 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 addressed loss of material for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-10. Based on its review of the GALL Report, stainless steel exposed to condensation external, an environment similar to raw water, 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 applicant's External Monitoring Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's proposal to manage loss of materials using the External Monitoring Program acceptable because it includes periodic visual inspections of component surfaces and will detect discoloration and surface discontinuities due to loss of 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 Floor and Equipment Drainage – 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 floor and equipment drainage component groups.

Carbon and Stainless Steel Closure Bolting Exposed to Waste Water. In LRA Table 3.3.2-10, the applicant stated that the carbon and stainless steel closure bolting exposed to waste water will be managed for loss of preload by the Bolting Integrity 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 applicant addressed loss of material for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-10. Based on its review of the GALL Report, item AP-264 states that loss of preload is an appropriate aging effect for steel and stainless steel bolting exposed to raw water, an environment similar to waste water from a preload perspective, and 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 applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.2. The staff finds the applicant's proposal to manage loss of preload using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload; and inspects for leakage bolted connections to ensure detection of leakage occurs before the leakage becomes excessive.

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).

3.3.2.3.11 Compressed Air – 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 compressed air component groups.

Stainless Steel Flexible Connections Exposed to Condensation. In LRA Table 3.3.2-11, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for stainless steel flexible connections exposed to condensation which cite generic note H. The staff confirmed that there is a TLAA as documented in LRA Section 4.3.2.2 for this component and material. The staff's evaluation of the fatigue TLAA for Non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

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).

3.3.2.3.12 Fire Protection – 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 fire protection – water component groups.

Carbon Steel Piping Exposed to Exhaust Gas. In LRA Table 3.3.2-12, the applicant stated there is a TLAA for carbon steel piping exposed to exhaust gas (internal), which 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 metal fatigue TLAA for non-Class 1 components is documented in SER Section 4.3.2.

Copper Alloy Greater Than 15 Percent Zinc or Greater Than 8 Percent Aluminum Flame Arrestor and Nozzles Exposed to Air-Outdoor (Internal). In LRA Table 3.3.2-12, the applicant stated that copper alloy greater than 15 percent zinc or greater than 8 percent aluminum flame arrestor exposed to outdoor air (internal) will be managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. By letter dated August 21, 2012, the applicant amended their LRA to include copper alloy with greater than 15 percent zinc or greater than 8 percent aluminum nozzles exposed to outdoor air (internal), which will also be managed for loss of material by the 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, item VII.I.AP-159, which states that copper-alloy piping, piping components, and piping elements exposed to outdoor air should be managed for loss of material using GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," 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 applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program includes visual inspections of metallic components, which are capable of detecting loss of material before loss of component intended function.

Carbon Steel Piping and Gray Cast Iron Flame Arrestors Exposed to Air Outdoor (Internal). In LRA Tables 3.3.2-12, 3.3.2-15, and 3.3.2-16, the applicant stated that carbon steel piping and gray cast iron flame arrestors exposed to outdoor air (internal) will be managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components. 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 gray cast iron is considered steel in the GALL Report when selective leaching is not a concern. Based on its review of the GALL Report, item VIII.B1-6 (SP-59), which states that steel components exposed internally to outdoor air should be managed for loss of material using GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," 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 applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because it includes visual inspections of metallic components, which are capable of detecting loss of material before loss of component intended function.

<u>Carbon Steel Piping Components Exposed to Raw Water</u>. The staff's evaluation for carbon steel piping components exposed to raw water, which will be managed for loss of material due to recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

<u>Metallic Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water</u>. As amended by letter dated November 6, 2014, in LRA Table 3.3.2-12, the applicant stated that metallic tanks with Service Level III or other internal coatings exposed to raw water will be managed for loss of coating integrity by the Fire Water System Program. The new AMR item cites generic note H, indicating that this aging effect for the component, material, and environment combination is not included in the GALL Report.

Based on its reviews of LRAs and industry operating experience, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. As a result, the staff issued RAI 3.0.3-2 on January 2, 2014, requesting that the applicant address loss of coating integrity for Service Level III and other coatings. In its response dated May 13, 2014, the applicant stated that it had identified components where coating degradation has the potential to adversely affect the passive functions of downstream components, which is an aging effect not addressed in the GALL Report. In its response dated November 6, 2014, the applicant added the internally coated fire water storage tanks to LRA Table 3.3.2-12.

The staff's evaluation of the applicant's use of the Fire Water System Program to manage loss of coating integrity is documented in SER Section 3.0.3.3. The staff noted that the applicant will make a number of enhancements to the programs to address loss of coating integrity, including internal visual inspections of the coated components. The staff finds the applicant's proposal to manage loss of coating integrity using the Fire Water System Program acceptable, because the program will include periodic visual inspections conducted by appropriately certified individuals, with specified acceptance criteria, and evaluations of inspection findings will be conducted by an appropriately qualified nuclear coatings subject matter expert, which will ensure that degradation of coating integrity is detected before causing a loss of intended function.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

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).

3.3.2.3.13 Fire Protection – Halon and CO_2 – 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 Fire Protection – Halon and CO_2 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.

3.3.2.3.14 Plant Chilled Water – 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 plant chilled water component groups.

Insulated, Carbon Steel and Stainless Steel Piping and Piping Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel and stainless steel piping and piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. The staff's evaluation for stainless steel piping, piping elements, and piping components externally exposed to condensation that will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note G, is documented in SER Section 3.2.2.3.7.

Carbon and Stainless Steel Closure Bolting Exposed to Condensation. The staff's evaluation for carbon and stainless steel closure bolting exposed to condensation that will be managed for loss of preload by the Bolting Integrity Program and cite generic note H, is documented in SER Section 3.3.2.3.7.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service

Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

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 Standby Diesel Generator – 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 standby diesel generator component groups.

Carbon Steel Piping and Gray Cast Iron Turbocharger Exposed Exhaust Gas. In LRA Table 3.3.2-15, the applicant stated there are TLAAs for carbon steel piping, CASS turbocharger, and gray cast iron turbocharger exposed to exhaust gas (internal), which cite 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 non-Class 1 components is documented in SER Section 4.3.2.

Carbon and Stainless Steel Closure Bolting Exposed to Lube Oil. In LRA Table 3.3.2-15, the applicant stated that the carbon and stainless steel closure bolting exposed to lube oil will be managed for loss of preload by the Bolting Integrity 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 applicant addressed loss of material for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-15. Based on its review of the GALL Report, item AP-264 states that loss of preload is an appropriate aging effect for steel and stainless steel bolting exposed to raw water, an environment similar to lube oil from a preload perspective, and 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 applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.2. The staff finds the applicant's proposal to manage loss of preload using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload; and inspects for leakage bolted connections to ensure detection of leakage occurs before the leakage becomes excessive.

Nickel Alloy Expansion Joint Exposed to Treated Water. In LRA Table 3.3.2-15, the applicant stated that nickel alloy expansion joints exposed to treated water (internal) will be managed for loss of material by the Water Chemistry Control – Closed Treated Water Systems 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 GALL Report items VII.C1.AP-206 and VII.E5.AP-279 for nickel alloys in raw water and waste water, respectively, state that nickel alloy piping components are subject to loss of material only. The staff also noted that the Metals Handbook, Desk Edition, Second Edition (ASM International, 1998) states that nickel and nickel-base alloys generally have very good corrosion resistance in distilled and fresh waters, and the ASM Handbook, Volume 13B, "Corrosion of Nickel and Nickel-Based Alloys" chapter (ASM International, 2005) states that nickel alloys are subject to SCC only in specific environments, such as hot caustic, fluoride, and chloride-containing water environments. Based on this review, 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 applicant's Water Chemistry Control – Closed Treated Water Systems Program is documented in SER Section 3.0.3.1.42. The staff finds the applicant's proposal to manage aging using the Water Chemistry Control – Closed Treated Water Systems Program acceptable because the water chemistry controls are capable of mitigating the environmental effects on loss of material and the opportunistic and periodic inspections can detect the presence or extent of corrosion prior to loss of intended function.

In LRA Table 3.3.2-15, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for nickel alloy expansion joints exposed to treated water (int) which cite generic note G. The staff confirmed that there is a TLAA as documented in LRA Section 4.3.2.2 for this component and material. The staff's evaluation of the fatigue TLAA for Non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

<u>Aluminum Housings Exposed to Condensation</u>. In LRA Table 3.3.2-15, the applicant stated that aluminum filter housings exposed to condensation will be managed for loss of material by the Compressed Air Monitoring Program. The AMR items cite generic note G. By letter dated June 22, 2012, the applicant amended the application and changed the AMR item to reference GALL Report item 3.3.1-92, and cite generic note E. As a result of the amendment, the staff's evaluation of this item is documented in SER Section 3.3.2.1.15, "Loss of Material Due to Pitting and Crevice Corrosion."

<u>Copper Alloy Greater Than 15 Percent Zinc (Inhibited) Heat Exchanger Tubes Exposed to Air-Indoor (External)</u>. In LRA Table 3.3.2-15, the applicant stated that copper alloy greater than 15 percent zinc (inhibited) heat exchanger tubes exposed to indoor air (external) will be managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G.

The staff noted that this material and environment combination is identified in the GALL Report, item VII.J.AP-144, which states that copper-alloy components exposed to uncontrolled indoor air have no AERM and no AMP is proposed. However, the applicant has identified fouling as an aging effect.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program includes visual inspections of metallic components, which are capable of detecting fouling prior to loss of component intended function.

Gray Cast Iron Flame Arrestors Exposed to Outdoor Air. The staff's evaluation for gray cast iron flame arrestors exposed to outdoor air (internal), which will be managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cites generic note G, is documented in 3.3.2.3.12.

Aluminum Heat Exchanger Fins Exposed to Air-Indoor (External). In LRA Tables 3.3.2-15 and 3.3.2-16 the applicant stated that aluminum heat exchanger fins exposed to indoor air (external) will be managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that aluminum piping, piping components, and piping elements exposed to air-indoor controlled (external) have no AERM and recommends no AMP. However, the applicant has fouling as an aging effect.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program includes visual inspections of metallic components, which are capable of detecting fouling prior to loss of component intended function.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

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).

3.3.2.3.16 HPCS Diesel Generator – 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 HPCS diesel generator component groups.

Carbon Steel and Gray Cast Iron Components Exposed to Exhaust Gas. In LRA Table 3.3.2-16, the applicant stated that there are TLAAs for stainless steel flexible connection, carbon steel piping, carbon turbocharger, and gray cast iron turbocharger exposed to exhaust gas (internal), which cite 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 non-Class 1 components is documented in SER Section 4.3.2.

Aluminum Housings Exposed to Condensation. In LRA Table 3.3.2-16, the applicant stated that aluminum air start motor housings exposed to condensation will be managed for loss of material by the Compressed Air Monitoring Program. The AMR items cite generic note G. By letter dated June 22, 2012, the applicant amended the application and changed the AMR item to reference GALL Report item 3.3.1-92 and cite generic note E. As a result of the amendment, the staff's evaluation of this item is documented in SER Section 3.3.2.1.15, "Loss of Material Due to Pitting and Crevice Corrosion."

Copper Alloy Greater Than 15 Percent Zinc or Greater Than 8 Percent Aluminum Valve Body Exposed to Exhaust Gas (Internal). In LRA Table 3.3.2-16 the applicant stated that copper alloy greater than 15 percent zinc or greater than 8 percent aluminum valve body exposed to exhaust gas (internal) will be managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components. 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 the GALL Report, the staff noted that copper alloy greater than 15 percent zinc or greater than 8 percent aluminum exposed to condensation is subject to a loss of material, and that exhaust gas usually contains condensation and other contaminants. The staff also noted that copper is only subject to cracking in the presence of ammonia, which is not expected to be part of exhaust gas. 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 applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program includes visual inspections of metallic components, which are capable of detecting loss of material prior to loss of component intended function.

Carbon Steel Heat Exchanger Components Exposed to Raw Water. By letter dated December 20, 2013, the applicant revised LRA Table 3.3.2-16 and stated that carbon steel heat exchanger components exposed to raw water will be managed for loss of material due to erosion by the Service Water Integrity Program. The AMR item cites generic note H and also cites plant-specific note 309, which states that the aging effect used for this item refers to loss of material due to erosion.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel heat exchanger components exposed to raw water are susceptible to loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and recommends GALL Report AMP XI.M20 to manage loss of material due to these mechanisms. However, the applicant has identified an additional mechanism. The applicant addressed the aging effects identified in the GALL Report for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-16.

The staff's evaluation of the Service Water Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage loss of material due to erosion mechanisms using the Service Water Integrity Program acceptable, because the program conducts periodic visual inspections of heat exchanger internals, which can detect loss of material prior to the loss of intended functions.

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).

<u>Gray Cast Iron Flame Arrestors Exposed to Outdoor Air</u>. The staff's evaluation for gray cast iron flame arrestors exposed to outdoor air (internal), which will be managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cites generic note G, is documented in 3.3.2.3.12.

<u>Aluminum Heat Exchanger Fins Exposed to Indoor Air</u>. The staff's evaluation for aluminum heat exchanger fins exposed to indoor air (external), which will be managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cites generic note H, is documented in 3.3.2.3.15.

<u>Copper-alloy Heat Exchanger Tubes Exposed to Treated Water</u>. In LRA Tables 3.3.2-15 and 3.3.2-16 the applicant stated that copper-alloy heat exchanger tubes exposed to treated water will be managed for loss of material due to wear by the Service Water Integrity Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that copper-alloy heat exchanger tubes exposed to treated water are susceptible to loss of material due to corrosion and recommends GALL Report AMP XI.M21A to manage this aging effect. However the applicant has identified loss of material due to wear as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-15 and 3.3.2-16.

The staff's evaluation of the applicant's Service Water Integrity Program is documented in SER Section 3.0.3.1.39, which includes loss of material. However, in its review of the this item, the staff could not determine the exact nature of the wear mechanism, and the LRA did not provide sufficient information for the staff to verify that the NDEs conducted through the Service Water Integrity Program will be effective in managing loss of material for the treated water side of the heat exchanger tubes. In order to address this concern, by letter dated June 27, 2012, the staff issued RAI 3.3.2.15-1 requesting the applicant to describe the nature of the aging mechanism and to describe the NDE method to be used on the heat exchanger tubes.

In its response dated July 25, 2012, the applicant stated that the wear is due to the relative motion between the tubes and tube support members and that this mechanism is evaluated for heat exchangers with very low run times because heat exchangers in continuous service will typically identify and correct these types of wear problems early in life. The applicant also stated that the Service Water Integrity Program conducts ongoing surveillances of heat exchangers subject to loss of material due to wear by periodically performing eddy current testing of tubes, which is capable of detecting wall thinning on the external surfaces of the tubes from the inside. The staff finds the applicant's response acceptable and the applicant's proposal to manage loss of material due to wear using the above program acceptable because the applicant clarified that the wear was caused by tube movement at the tube support plates and the periodic eddy current testing performed on these heat exchanger tubes by the Service Water Integrity Program can identify wall thinning prior to loss of intended function. The staff's concerns described in RAI 3.3.2.15-1 are resolved.

Stainless Steel Flexible Connections Exposed to Indoor Air. In LRA Table 3.3.2-16, as amended by letter dated October 22, 2012, the applicant stated there is a TLAA for stainless steel flexible connections exposed to air indoor (int), fuel oil, and condensation, respectively, which cite generic note H. The staff confirmed that there is a TLAA as documented in LRA Section 4.3.2.2 for this component and material. The staff's evaluation of the fatigue TLAA for Non-Class 1 expansion joints is documented in SER Section 4.3.2.2.2.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

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 Control Room Heating, Ventilation, and Air Conditioning – 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 Control Room Heating, Ventilation, and Air Conditioning component groups.

Insulated, Carbon Steel, Stainless Steel, and Copper Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel, stainless steel, and copper alloy piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Copper-Alloy Evaporator Tube Fins, Tubes, and Heat Exchanger Tubes Exposed to Condensation (External). In LRA Tables 3.3.2-17 and 3.3.2-18 the applicant stated that copper-alloy evaporator tube fins, evaporator tubes, and heat exchanger tubes exposed to condensation (external) will be managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that piping, piping components, and piping elements exposed to condensation (external) are susceptible to loss of material due to general, pitting, and crevice corrosion. However, the applicant has identified loss of material due to general, pitting, and crevice corrosion and fouling as an additional aging effect. The applicant addressed the GALL Report-identified aging effects for this component, and material and environment combination in other AMR items, in LRA Tables 3.3.2-17 and 3.3.2-18.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program includes visual inspections of metallic components, which are capable of detecting fouling prior to loss of component intended function.

Elastomeric Duct Flexible Connection Exposed to Interior Indoor Air. In LRA Table 3.3.2-17, the applicant stated that for elastomeric duct flexible connection exposed internally to indoor air, there is no aging effect and no AMP is proposed. The AMR item cites generic note I. The AMR item also cites plant-specific note 306 which states, "[c]hanges of material properties and cracking in elastomers are results of exposure to ultra-violet light or elevated temperatures (> 95 °F). The interior surfaces of these components are not exposed to ultra-violet light and are part of the control room HVAC system that is not exposed to elevated temperatures." The applicant also cited LRA Table 3.3.1, item 3.3.1-76. The staff noted that SRP-LR item 3.3.1-76 recommends managing elastomeric materials for hardening and loss of strength due to elastomer degradation with GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." The staff also noted that LRA item 3.3.1-76 recommends the same.

The staff could not confirm that there are no aging effects for this material and environment combination for this component, material, and environmental combination. The staff noted that GALL Report Section IX.C states, "[h]ardening and loss of strength of elastomers can be induced by elevated temperature (over about 95 °F or 35 °C), and additional aging factors (e.g., exposure to ozone, oxidation, and radiation)." Nevertheless, the 95 °F is a general guideline and does not necessarily apply to all elastomeric material types. By letter dated June 20, 2012, the staff issued RAI 3.3.1.76-1 requesting that the applicant state the specific material type for these elastomeric duct flexible connection(s), state the basis why there are no AERM and no proposed AMP, and if the specific elastomeric material type does age despite being in an environment below 95 °F, state how the item will be managed for aging.

In its response dated July 19, 2012, the applicant stated that the elastomeric duct flexible connection is constructed from neoprene coated fiberglass cloth. The applicant also stated that, "[n]eoprene is chemically and structurally similar to natural rubber, with similar mechanical properties. It has high resistance to oils, chemicals, sunlight, weathering, aging, and ozone. It retains its properties at temperatures up to 250 °F (121.1 °C)." The applicant further stated that, "[n]o aging effects requiring management (AERM) and no proposed aging management programs (AMP) are identified for the internal surface of these elastomers since they are not exposed to ultra-violet light or elevated temperatures (greater than 95 °F)."

The staff finds the applicant's response acceptable because neoprene is recognized for being weather and ozone resistant and it has excellent abrasion and tear resistance (Tank Linings for Chemical Process Industries, Chandrasekaran, V.C.© 2009 Smithers Rapra Technology) and as stated in plant-specific note I, the duct flexible connections are not exposed to ultraviolet light or temperatures above 95 °F. The staff's concern described in RAI 3.3.1.76-1 is resolved.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

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).

3.3.2.3.18 Heating, Ventilation, and Air Conditioning – 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 HVAC component groups.

Copper-Alloy Evaporator Tube Fins, Tubes, and Heat Exchanger Tubes Exposed to Condensation (External). The staff's evaluation for copper-alloy heat exchanger tubes exposed to condensation (external) that will be managed for fouling by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cites generic note H, is documented in SER Section 3.3.2.3.17.

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).

3.3.2.3.19 Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) – 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 miscellaneous auxiliary systems in scope for 10 CFR 54.4(a)(2) component groups.

For LRA Table 3.3.2-19-1

Carbon Steel Piping Components Exposed to Treated Water. The staff's evaluation for carbon steel piping components exposed to treated water, which will be managed for loss of material due to erosion mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.3.2.3.1.

For LRA Table 3.3.2-19-2

Stainless Steel Expansion Joint Exposed to Treated Water. In LRA Table 3.3.2-19-2, the applicant stated there is a TLAA for stainless steel expansion joint exposed to treated water (int), which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.2.2, for this component and material. The staff's evaluation of the fatigue TLAA for non-Class 1 components is documented in SER Section 4.3.2.2.2.

For LRA Table 3.3.2-19-7

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-8

Teflon Flexible Connections Exposed to Treated Water (internal). In LRA Table 3.3.2-19-8, the applicant stated that for Teflon flexible connections exposed to treated water (internal), there is no aging effect and no AMP is proposed. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environmental combination. The staff could not find the applicant's proposal acceptable based on its review of NASA Technical Memorandum 105753, High Temperature Dielectric Properties of Apical, Kapton, Peek, Teflon AF, and Upilex Polymers, A N Hammoud, 1992, Table 1, which states that Teflon can handle long-term temperatures up to 285 °C; however, there are studies which demonstrate that certain grades of Teflon degrade when exposed to radiation. By letter dated June 20, 2012, the staff issued RAI 3.3.2.19-3 requesting that the applicant state the specific Teflon material type for these flexible connections, state the basis why there are no AERM and no proposed AMP, and if the specific Teflon material type does age, state how the item will be managed for aging.

In its response dated July 19, 2012, the applicant stated that:

> After a review of operating use information for this component, it was determined that the flexible connection in question is a single short length of material located downstream of a normally closed sample valve. After use, the flexible connection sample line is allowed to drain and empty. The flexible connection is normally isolated and drained, not fluid-filled. This nonsafety-related component therefore has no potential for physical interaction with a safety-related component. Based on these details, this flexible connection is not subject to aging management review. LRA Table 3.3.2-19-8 is revised to reflect these details. Deletions are shown with strikethrough.

The staff finds the applicant's response acceptable because it clearly explained why these components are not subject to an AMR and the LRA has been appropriately amended. The staff's concern described in RAI 3.3.2.19-3 is resolved.

Carbon Steel Piping Components Exposed to Treated Water. The staff's evaluation for carbon steel piping components exposed to treated water, which will be managed for loss of material due to erosion mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.3.2.3.1.

For LRA Table 3.3.2-19-9

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-14

Insulated, Carbon Steel and Stainless Steel Piping Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel and stainless steel piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

For LRA Table 3.3.2-19-15

Insulated, Carbon Steel and Stainless Steel Piping Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel and stainless steel piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

For LRA Table 3.3.2-19-16

Carbon and Stainless Steel Closure Bolting Exposed to Condensation. The staff's evaluation for carbon and stainless steel closure bolting exposed to condensation that will be managed for loss of preload by the Bolting Integrity Program and cite generic note H is documented in SER Section 3.3.2.3.7.

Carbon Steel Piping Components Exposed to Raw Water. The staff's evaluation for carbon steel piping components exposed to raw water, which will be managed for loss of material due to recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Insulated Carbon Steel Piping and Piping Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel piping components exposed to external condensation, which will be managed for loss of material by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service

Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-17

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-18

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-19

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. The staff's evaluation for stainless steel piping, piping elements, and piping components externally exposed to condensation that will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note G is documented in SER Section 3.2.2.3.7.

Plastic Sight Glass Exposed to Raw Water or Condensation (Internal). By letter dated August 15, 2012, the applicant amended LRA Table 3.3.2-19-19 to include items for plastic sight glass exposed to raw water (internal) and condensation (external), which will be managed for a change in material properties by the Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Programs. 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 reviewed the Engineering Materials Handbook – Engineering Plastics, American Society for Metals International, Copyright 1988, which states that rigid polymers are unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, sunlight, or humidity changes. The staff also noted that, unlike metals, thermoplastics do not display corrosion rates, and rather than depend on an oxide layer for protection, they depend on chemical resistance to the environments to which they are exposed. The staff further noted that thermoplastic materials are impervious and, once selected for the environment, will not have any significant age related degradation. Based on its review of the associated items in the LRA and the reference above, the staff confirmed that the applicant has identified all credible aging effects for this component, material and environmental combination.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Programs are documented in SER Sections 3.0.3.1.25 and 3.0.3.1.17. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Programs acceptable because the programs include periodic visual inspections which are capable of detecting a change in material properties (e.g., change in clarity, cracking, crazing) prior to a loss of component intended function.

Carbon Steel and Stainless Steel Piping Components Exposed to Raw Water. The staff's evaluation for carbon steel and stainless steel piping components exposed to raw water, which will be managed for loss of material due to recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Insulated, Carbon Steel and Stainless Steel Piping and Piping Components Exposed to External Condensation. The staff's evaluation for insulated carbon steel and stainless steel piping and piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

For LRA Table 3.3.2-19-20

Carbon Steel Piping Components Exposed to Treated Water. The staff's evaluation for carbon steel piping components exposed to treated water, which will be managed for loss of material due to erosion mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.3.2.3.1.

For LRA Table 3.3.2-19-23

Carbon Steel Piping Components Exposed to Raw Water. The staff's evaluation for carbon steel piping components exposed to raw water, which will be managed for loss of material due to recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program and which are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-24

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service

Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-25

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. The staff's evaluation for stainless steel piping, piping elements, and piping components externally exposed to condensation that will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note G is documented in 3.2.2.3.7.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-26

Stainless Steel Piping, Piping Elements, and Piping Components Exposed to External Condensation. The staff's evaluation for stainless steel piping, piping elements, and piping components externally exposed to condensation that will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note G, is documented in 3.2.2.3.7.

Insulated Carbon Steel Piping Components Exposed to an External Condensation Environment. The staff's evaluation for insulated carbon steel piping components exposed to external condensation, which will be managed for loss of material and cracking by the External Surfaces Monitoring Program and are associated with generic note H, is documented in SER Section 3.3.2.3.7.

Carbon and Stainless Steel Closure Bolting Exposed to Condensation. The staff's evaluation for carbon and stainless steel closure bolting exposed to condensation that will be managed for loss of preload by the Bolting Integrity Program and cite generic note H, is documented in SER Section 3.3.2.3.7.

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-27

Metallic Heat Exchanger Components, Piping, and Tanks with Service Level III or Other Internal Coatings Exposed to Raw Water, Fuel Oil, Treated Water, or Lube Oil. The staff's evaluation for metallic heat exchanger components, piping, and tanks with Service Level III or other internal coatings exposed to raw water, fuel oil, treated water, or lube oil, which will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance or Service

Water Integrity Programs and which are associated with generic note H, is documented in SER Section 3.3.2.3.5.

For LRA Table 3.3.2-19-28

Stainless Steel Flexible Connections Exposed to Raw Water. In LRA Table 3.3.2-19-28, the applicant stated there is a TLAA for stainless steel flexible connections exposed to raw water (int), which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.2.2, for this component and material. The staff's evaluation of the fatigue TLAA for non-Class 1 components is documented in SER Section 4.3.2.2.2.

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).

3.3.3 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 section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion systems components and component groups of:

- condensate and refueling water storage and transfer
- miscellaneous steam and power conversion systems in scope for 10 CFR 54.4(a)(2)

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 the issuance of the GALL Report.

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 which 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/ 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 due to 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 due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring	Consistent with the GALL Report (see SER Section 3.4.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect/ 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; tanks exposed to air – outdoor (3.4.1-3)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring	Consistent with the GALL Report (see SER Section 3.4.2.2.3)
Steel external surfaces, bolting exposed to air with borated water leakage (3.4.1-4)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Not applicable	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 due to 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	Bolting Integrity	Consistent with the GALL Report
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-7)	Cracking due to cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to GGNS (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 due to 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 (3.4.1-9)	Loss of material due to general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to GGNS (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 due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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, tanks, heat exchanger components exposed to steam, treated water >60 °C (>140 °F) (3.4.1-11)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR and One-Time Inspection	Consistent with the GALL Report
Steel; stainless steel tanks exposed to treated water (3.4.1-12)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to 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 3.4.2.1.1)
Steel piping, piping components, and piping elements, PWR heat exchanger components exposed to steam, treated water (3.4.1-14)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR and One-Time Inspection	Consistent with the GALL Report
Steel heat exchanger components exposed to treated water (3.4.1-15)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR and One-Time Inspection	Consistent with the GALL Report
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 due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy, stainless steel heat exchanger tubes exposed to treated water (3.4.1-18)	Reduction of heat transfer due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Control – BWR 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 due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Internal Surfaces in Miscellaneous Piping and Ducting Components or Periodic Surveillance and Preventive Maintenance	Consistent with the GALL Report (see SER Section 3.4.2.1.2)
Copper alloy, stainless steel piping, piping components, and piping elements exposed to raw water (3.4.1-20)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.4.2.1.3)
Stainless steel heat exchanger components exposed to raw water (3.4.1-21)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Stainless steel, copper alloy, Steel heat exchanger tubes, heat exchanger components exposed to raw water (3.4.1-22)	Reduction of heat transfer due to fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to GGNS (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 due to stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to GGNS (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 due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-25)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report
Stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-26)	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-27)	Loss of material due to pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Water Chemistry Control – Closed Treated Water Systems	Consistent with the GALL Report
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 due to fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to GGNS (see SER Section 3.4.2.1.1)
Steel tanks exposed to air – outdoor (external) (3.4.1-29)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Not applicable	Not applicable to GGNS (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 due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report (see SER Section 3.4.2.1.5)
Stainless steel, aluminum tanks exposed to soil or concrete (3.4.1-31)	Loss of material due to pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report
Gray cast iron piping, piping components, and piping elements exposed to soil (3.4.1-32)	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to GGNS (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching	Consistent with the GALL Report
Steel external surfaces exposed to air – indoor, uncontrolled (external), air – outdoor (external), condensation (external) (3.4.1-34)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to air – outdoor (3.4.1-35)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to GGNS (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 due to general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Steel piping, piping components, and piping elements exposed to condensation (internal) (3.4.1-37)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-38)	Loss of material due to 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	Not applicable	Not applicable to BWRs (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 due to pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to GGNS (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 lubricating oil (3.4.1-40)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Oil Analysis, One-Time Inspection, and Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.4.2.1.4)
Steel heat exchanger components exposed to lubricating oil (3.4.1-41)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	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 due to pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	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 due to pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements, heat exchanger components exposed to lubricating oil (3.4.1-44)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	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 due to fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	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 due to fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with coating or wrapping) piping, piping components, and piping elements; tanks exposed to soil or concrete (3.4.1-47)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried Piping and Tanks Inspection	Consistent with the GALL Report
Stainless steel bolting exposed to soil (3.4.1-48)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried Piping and Tanks Inspection	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.4.1-49)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried Piping and Tanks Inspection	Consistent with the GALL Report
Steel bolting exposed to soil (3.4.1-50)	Loss of material due to general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried Piping and Tanks Inspection	Consistent with the GALL Report
Underground stainless steel and steel piping, piping components, and piping elements (3.4.1-50x)	Loss of material due to general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to GGNS (see SER Section 3.4.2.1.1)
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 operating experience indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to GGNS (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	Not applicable	Not applicable to GGNS (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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	Not applicable	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	Not applicable	Consistent with the GALL Report
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	Not applicable	Consistent with the GALL Report
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	Not applicable	Consistent with the GALL Report
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	Not applicable	Not applicable to GGNS (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	Not applicable	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ 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 air – indoor controlled (external), gas (3.4.1-59)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to GGNS (see SER Section 3.4.2.1.1)

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:

- Aboveground Metallic Tanks
- Bolting Integrity
- Buried Piping and Tanks Inspection
- Compressed Air Monitoring
- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Internal Surfaces in Miscellaneous Piping and Ducting Components
- Oil Analysis
- One-Time Inspection
- Periodic Surveillance and Preventive Maintenance
- Selective Leaching
- Water Chemistry Control – BWR
- Water Chemistry Control – Closed Treated Water Systems

LRA Tables 3.4.2-1 through 3.4.2-2 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.

3.4.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.4.1, items 3.4.1-4, 3.4.1-17, 3.4.1-21, 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 that these items are not applicable to GGNS.

For LRA Table 3.4.1, items 3.4.1-7, 3.4.1-22, 3.4.1-23, 3.4.1-28, 3.4.1-29, 3.4.1-32, 3.4.1-35, 3.4.1-51, 3.4.1-52, and 3.4.1-57, the applicant claimed that the corresponding items in the GALL Report are 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.

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 due to general corrosion for this component group. The applicant stated that this item is not applicable because steam or water leakage is not considered a separate aspect of the indoor air environment. The staff evaluated the applicant's claim and found it acceptable because (a) all ESF system bolting exposed to air is being managed for loss of material by the Bolting Integrity Program using item 3.4.1-08, (b). The program conducts periodic visual inspections that are capable of detecting loss of material due to general corrosion in bolting, and (c) use of this program is consistent with the GALL Report.

LRA Table 3.4.1, item 3.4.1-13 addresses steel 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 due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because it is applicable to PWR plants only. The staff evaluated the applicant's claim and found it acceptable because, although the LRA contains steel piping components exposed to treated water in the steam and power conversion systems, the staff confirmed that those components reference LRA item 3.4.1-14, which manages loss of material due to general, pitting, and crevice corrosion in a manner consistent with LRA item 3.4.1-13 and GALL Report recommendations.

LRA Table 3.4.1, item 3.4.1-37 addresses steel piping, piping components, and piping elements exposed to condensation (internal.) The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage loss of material for this component group. The applicant stated that this item is not applicable because it is only applicable to PWRs. The staff evaluated the applicant's claim and finds it acceptable because the GALL Report items that are referenced by item 3.4.1-37 are for the main steam and auxiliary feedwater systems, which are applicable only for PWRs. However, the staff noted that there are AMR items in LRA Table 3.4.2-2-16 with this material, environment, and aging effect combination for which the applicant credits LRA Table 3.3.1, item 3.3.1-95 and the Internal Surfaces in Miscellaneous Piping and Ducting Program to manage aging.

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 due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion, 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. Nevertheless, the staff evaluated the applicant's claim and found it acceptable because, although the LRA contains steel piping components exposed to raw water in the steam and power conversion systems, the applicant chose to reference LRA item 3.4.1-19, which manages aging with either the Internal Surfaces in Miscellaneous Piping and Ducting Components or Periodic Surveillance and Preventive Maintenance Programs. The staff also noted that the periodic visual examinations in the Internal Surfaces in Miscellaneous Piping and Ducting Components and Periodic Surveillance and Preventive Maintenance Programs are capable of detecting loss of material and fouling prior to loss of intended functions.

LRA Table 3.4.1, item 3.4.1-39 addresses stainless steel piping, piping components, and piping elements exposed to condensation (internal). The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage loss of material for this component group. The applicant stated that this item is not used because loss of material for this component group is managed by the Compressed Air Monitoring System consistent with LRA Table 3.3.1, item 3.3.1-56. The staff evaluated the applicant's claim and finds it acceptable because the applicant is managing aging for this material, environment, and aging effect combination consistent with the GALL Report using alternative Table 1 items.

LRA Table 3.4.1, item 3.4.1-50.5 addresses stainless steel, and steel underground piping, piping components, and piping elements. The GALL Report recommends GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," to manage loss of material due to general (steel only), pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because "[t]here is no underground piping in areas of restricted access in the steam and power conversion systems in the scope of license renewal." The staff evaluated the applicant's claim and lacks sufficient information to find it acceptable because an enhancement to LRA Section B.1.18, External Surfaces Monitoring Program, states that instructions will be provided for inspecting all underground components within the scope of this program. Based on the staff's review during the AMP audit, the RHR pump suction barrels and HPCS pump suction barrels are two of the underground piping components associated with this enhancement. Although these components are not within the scope of LRA Section 3.4, a similar non-applicability statement was made associated with item 3.2.1-53.5 when the enhancement demonstrates that there are underground components in LRA Section 3.2. By letter dated April 16, 2012, the staff issued RAI B.1.5-1 requesting that the applicant provide a list of all underground in-scope components, state which AMP will be used to manage the aging of these underground in-scope components, and if a program other than the Buried Piping and Tanks Inspection Program will be used to age manage any of the underground components, state if any recommendations contained in AMP XI.M41 of the GALL Report will not be met and justify not meeting the recommendations. In its response dated May 14, 2012, the applicant listed the underground components, none of which are steam and power conversion components. The staff finds the applicant's response acceptable because there are no in-scope underground components in the steam and power conversion components systems. The staff's concern described in RAI B.1.5-1 is resolved.

LRA Table 3.4.1, item 3.4.1-55, addresses glass piping elements exposed to lubricating oil, outdoor air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water, and uncontrolled indoor air. The applicant stated that it is consistent with the GALL Report for glass components exposed to indoor air, lube oil, raw water, and treated water, but that for other environments there are no glass components within the steam and power conversion systems that are within the scope of license renewal. SRP-LR

Table 3.4-1, item 3.4.1-55 states that there are no aging effects or aging mechanisms, and that no AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.4.1, item 3.4.1-59 addresses steel piping, piping components, and piping elements exposed to air – indoor, controlled (external) and gas and states that there are no aging effects, aging mechanisms, or AMPs. SRP-LR item 3.4.1-59 recommends that there is no aging effect, aging mechanism, and that no AMP is recommended for this component group exposed to this environment; therefore, the staff finds the applicant's determination acceptable.

3.4.2.1.2 Loss of Material Due to General, Pitting, Crevice, Galvanic, and Microbiologically-influenced Corrosion, Fouling That Leads to Corrosion

LRA Table 3.4.1, item 3.4.1-19 addresses steel and stainless steel heat exchanger components exposed to raw water, which are being managed for loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting Components and Periodic Surveillance and Preventive Maintenance Program to manage loss of material for carbon steel filter housings, flow elements, piping, pump casings, sight glasses, tanks, and valves, and cast iron valves. The GALL Report recommends AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The GALL Report recommends using visual inspections to manage aging. The staff notes that these components are only associated with the CW system; therefore, it is not part of GALL Report AMP XI.M20 because the CW system is not within the scope of GL 89-13.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components and Periodic Surveillance and Preventive Maintenance Programs are documented in SER Sections 3.0.3.1.25 and 3.0.3.2.2, respectively. The staff notes that both programs propose to manage the aging of carbon steel and cast iron piping and components through the use of periodic visual inspections. In its review of components associated with item 3.4.1-19, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the above cited programs acceptable because the Internal Surfaces in Miscellaneous Piping and Ducting Components Program conducts periodic visual inspections and is the recommended AMP to manage the same aging effects for the same material for item 3.4.1-38, which would be appropriate since the CW system is not managed by GALL Report AMP XI.M20. The staff also notes that the Periodic Surveillance and Preventive Maintenance Program specifically states that the internal surfaces of a representative sample of piping and valve bodies in the CW system will be visually inspected as part of the program, which is capable of detecting loss of material due to various corrosion mechanisms.

The staff concludes that for LRA item 3.4.1-19, 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 Loss of Material Due to Pitting, Crevice, and Microbiologically-influenced Corrosion; Fouling That Leads to Corrosion

LRA Table 3.4.1, item 3.4.1-20 addresses copper-alloy and stainless steel piping and piping components exposed to raw water, which will be managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting program to manage loss of material for copper-alloy and stainless steel components exposed to raw water in piping components. The GALL Report recommends GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” to ensure these aging effects are adequately managed. The staff notes that these components are only associated with the CW system, which is not part of GALL Report AMP XI.M20 because the CW system is not within the scope of GL 89-13.

The staff’s evaluation of the applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff notes that this program proposes to manage the aging of copper-alloy and stainless steel piping and components through the use of periodic visual inspections. In its review of components associated with item 3.4.1-12, for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage aging using the above cited programs acceptable because the Internal Surfaces in Miscellaneous Piping and Ducting Components Program conducts periodic visual inspections capable of detecting loss of material due to various corrosion mechanisms, and because the CW system is not managed by GALL Report AMP XI.M20, since it is not within the scope of GL 89-13.

The staff concludes that for LRA item 3.4.1-20, 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).

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

LRA Table 3.4.1, item 3.4.1-40 addresses steel piping, piping components, and piping elements exposed to lubricating oil that will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect carbon steel fan housing exposed to lubricating oil. The GALL Report recommends GALL Report AMP XI.M39, “Lubricating Oil Analysis,” to ensure that these aging effects are adequately managed. GALL Report AMP XI.M39 recommends performing periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with industry standards to manage aging.

The staff’s evaluation of the applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.25. The staff noted that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of carbon steel filters, filter housing, and fan housing through the use of visual inspections. In its review of components associated with items 3.3.1-97 and 3.4.1-40 for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because visual inspections will ensure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

The staff concludes that for LRA item 3.4.1-40, 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).

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

LRA Table 3.4.1, item 3.4.1-30 addresses steel, stainless steel, and aluminum tanks exposed to soil, concrete, or air – outdoor (external) which will be managed for loss of material due to general, pitting, and crevice corrosion. As amended by letter dated May 13, 2014, for the AMR items that cite generic note E, the LRA credits the Fire Water System Program to manage the aging effect for the fire water tank. 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 examinations to manage aging.

Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02, which revised several AMPs, including the guidance for AMP XI.M27, "Fire Water System." The revised AMP XI.M27 recommends that aging effects associated with fire water tanks be managed by AMP XI.M27 in lieu of AMP XI.M29. The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.1.20. In its review of components associated with item 3.4.1-30 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable, because it is consistent with LR-ISG-2012-02.

The staff concludes that, for LRA item 3.4.1-30, 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).

3.4.2.1.6 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed are not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed are not applicable are not applicable to GGNS.

As discussed in SER Section 3.4.2.1, 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 due to SCC

- loss of material due to 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 AMR 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, except as identified below.

The staff identified that the applicant did not include the applicable AMR items in LRA Tables 3.4 for the TLAAs associated with fatigue of non-Class 1. The staff noted that LRA Section 4.3.2 discusses the TLAAs associated with fatigue of non-Class 1 piping and states that these TLAAs will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Therefore, as part of the RAI 3.2.2-1, the staff requested the applicant to justify this discrepancy. The details of RAI 3.2.2-1 and the staff's evaluation of the applicant's response are documented in SER Section 3.2.2.2.1.

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 Due to Stress Corrosion Cracking

LRA Section 3.4.2.2.2, which is associated with LRA Table 3.4.1 item 3.4.1-2, addresses stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor that will be managed for cracking due to SCC by the Aboveground Metallic Tanks or External Surfaces Monitoring Program. The criteria in SRP-LR Section 3.4.2.2.2 states that cracking due to SCC could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air and that the possibility of cracking extends to components exposed to air that has been recently introduced into the building, such as components near intake vents. The SRP-LR also states that GALL Report AMP XI.M36, "External Surfaces Monitoring," is an acceptable method to manage the aging effect.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that cracking of stainless steel components directly exposed to outdoor air is managed by the External Surfaces Monitoring Program and there are no stainless steel components in the steam and power conversion systems within the scope of license renewal that are located next to unducted air intakes. The applicant also stated that the stainless steel CST exposed to air-outdoor that will be managed for cracking due to SCC by the Aboveground Metallic Tanks Program to be consistent with LR-ISG2012-02.

The staff's reviews of the applicant's Aboveground Metallic Tanks and External Surfaces Monitoring Programs are documented in SER Section 3.0.3.1.1 and 3.0.3.1.17, respectively. In its review of components associated with item 3.4.1-2, the staff finds that the applicant has met the further evaluation criteria as described below.

- The applicant's proposal to manage cracking using the External Surfaces Monitoring Program is acceptable because the program includes visual inspections of metallic components that are capable of detecting cracking prior to loss of component intended function, consistent with the SRP-LR recommendations.
- The applicant's proposal to manage cracking of the stainless steel CST using the Aboveground Metallic Tanks Program is acceptable because in addition to performing the periodic visual inspections recommended in GALL Report AMP XI.M36, the program also uses thickness measurements and preventive measures to manage aging.

The staff determines that the applicant's program meets SRP-LR Section 3.4.2.2.2 criterion. For those AMR items associated with LRA Section 3.4.2.2.2, 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).

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Section 3.4.2.2.3, which is associated with LRA Table 3.4.1 item 3.4.1-3, addresses stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor that will be managed for loss of material due to pitting and crevice corrosion by the External Surface Monitoring Program. The criteria in SRP-LR Section 3.4.2.2.3 states that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air and that possibility of loss of material due to pitting and crevice corrosion extends to components exposed to air that has been recently introduced into the building, such as components near intake vents. The SRP-LR also states that GALL Report AMP XI.M36, "External Surfaces Monitoring," is an acceptable method to manage the aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material from stainless steel components directly exposed to outdoor air is managed by the External Surfaces Monitoring Program and there are no stainless steel components in the steam and power conversion systems within the scope of license renewal that are located next to unducted air intakes.

The staff's review of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.1.17. In its review of components associated with item 3.4.1-3, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage loss of material using the External Surfaces Monitoring Program is acceptable because the program includes visual inspections of metallic components that are capable of detecting loss of material prior to loss of component intended function, consistent with the SRP-LR recommendations.

The staff determines that the applicant's program meets SRP-LR Section 3.4.2.2.3 criterion. For those AMR items associated with LRA Section 3.4.2.2.3, 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).

3.4.2.2.4 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.

3.4.2.2.5 Loss of Material Due to Recurring Internal Corrosion

By letter dated May 5, 2014, the applicant addressed recurring internal corrosion that is described in Section A and Appendix B of LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation." LR-ISG-2012-02 includes a new section (Section 3.4.2.2.6, Loss of Material Due to Recurring Internal Corrosion) in the SRP-LR for "AMR Results for Which Further Evaluation Is Recommended by the GALL Report."

Based on its review of plant-specific operating experience for the past 5 years, the applicant stated that microbiologically-influenced corrosion of piping components is a recurring internal corrosion issue as defined in LR-ISG-2012-02, Section A. The applicant further stated that it monitors loss of material in piping components due to microbiologically-influenced corrosion in the CW system, which is part of the Steam and Power Conversion section of the LRA. The staff's evaluation of the applicant's activities to manage recurring internal corrosion in all of the plant systems is documented in SER Section 3.3.2.2.7.

3.4.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-2, 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 3.4.2-2, 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.

3.4.2.3.1 Condensate and Refueling Water Storage and Transfer – 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 condensate and refueling water storage and transfer 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.

3.4.2.3.2 Miscellaneous Steam and Power Conversion Systems in Scope for 10 CFR 54.4(a)(2) - Summary of Aging Management Review – LRA Table 3.4.2-2

The staff reviewed the 19 LRA tables associated with Table 3.4.2-2, which summarizes the results of AMR evaluations for the miscellaneous steam and power conversion systems in scope for 10 CFR 54.4(a)(2) component groups.

For LRA Table 3.4.2-2-2

Stainless Steel Thermowell Exposed to Steam. In LRA Table 3.4.2-2-2, the applicant stated there is a TLAA for stainless steel thermowell exposed to steam (internal), which cite 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 non-Class 1 components is documented in SER Section 4.3.2.

For LRA Tables 3.4.2-2-3 and 3.4.2-2-4

Stainless Steel Expansion Joint Exposed to Steam. In LRA Table 3.4.2-2-3, the applicant stated there is a TLAA for stainless steel expansion joint exposed to steam (internal), which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

Metallic Tanks with Service Level III or Other Internal Coatings Exposed to Treated Water. As amended by letter dated May 13, 2014, in LRA Tables 3.4.2-2-3 and 3.4.2-2-4 the applicant stated that metallic tanks with Service Level III or other internal coatings exposed to treated water will be managed for loss of coating integrity by the Periodic Surveillance and Preventive Maintenance Program. The new AMR items cite generic note H, indicating that this aging effect for the component, material, and environment combination is not included in the GALL Report.

Based on its reviews of LRAs and industry operating experience, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. As a result, the staff issued RAI 3.0.3-2 on January 2, 2014, requesting that the applicant address loss of coating integrity for Service Level III and other coatings. In its response dated May 13, 2014, the applicant stated that it had identified components where coating degradation has the potential to adversely affect the passive functions of downstream components, which is an aging effect not addressed in the GALL Report.

The staff's evaluation of the applicant's use of the Periodic Surveillance and Preventive Maintenance Program to manage loss of coating integrity is documented in SER Section 3.0.3.3. The staff noted that the applicant will make a number of enhancements to the programs to address loss of coating integrity, including internal visual inspections of the coated components. The staff finds the applicant's proposal to manage loss of coating integrity using the above program acceptable, because the Periodic Surveillance and Preventive Maintenance Program will include periodic visual inspections conducted by appropriately certified individuals, with specified acceptance criteria, and evaluations of inspection findings will be conducted by an appropriately qualified nuclear coatings subject matter expert, which will ensure that degradation of coating integrity is detected before causing a loss of intended function.

For LRA Tables 3.4.2-2-4, 3.4.2-2-6, and 3.4.2-2-11

<u>Carbon Steel Piping Components Exposed to Treated Water</u>. By letter dated December 18, 2012, the applicant revised LRA Tables 3.4.2-2-4, 3.4.2-2-6, and 3.4.2-2-11, and stated that carbon steel piping components exposed to treated water will be managed for loss of material by the Flow-Accelerated Corrosion Program. The AMR items cite generic note H and also cite plant-specific note 403 which states that the Flow-Accelerated Corrosion Program also manages loss of material due to erosion mechanisms other than flow-accelerated corrosion.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel piping components exposed to treated water are susceptible to loss of material due to general, pitting, crevice, and flow-accelerated corrosion and recommends GALL Report AMP XI.M2, AMP XI.M32, and AMP XI.M17 to manage the aging effect due to these mechanisms. However the applicant has identified additional aging mechanisms. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in other AMR items in LRA Tables 3.4.2-2-4, 3.4.2-2-6, and 3.4.2-2-11.

The staff's evaluation of the applicant's Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.1.21. The staff finds the applicant's proposal to manage loss of material due to erosion mechanisms other than flow-accelerated corrosion using the Flow-Accelerated Corrosion Program acceptable, because the associated components can be treated similar to "susceptible-not-modeled" components currently within the program, which ensures that the consequent wall thinning will be detected before loss of intended function.

For LRA Table 3.4.2-2-5

<u>Insulated Carbon Steel Piping and Piping Components Exposed to External Condensation</u>. As modified by letter dated May 13, 2014, LRA Table 3.4.2-2-5 states that insulated carbon steel piping and piping components exposed to external condensation will be managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note H and includes a plant-specific note stating that the program provisions apply for indoor insulated components operating below the dew point.

The staff noted that this material and environment combination is not identified for insulated piping components in the GALL Report. Corrosion under insulation is addressed in LR-ISG-2012-02, Section E, and the applicant addressed this aspect in its response dated May 13, 2014, to the staff's RAI 3.0.3-1. The staff noted that the applicant appropriately addressed the aging effects identified in the GALL Report for noninsulated components for this material and environment combination in other AMR items in LRA Table 3.4.2-2-5.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's proposal to use this program to manage loss of material for insulated carbon steel components exposed to an external condensation environment acceptable, because it is consistent with the staff recommendations for managing this material and environment combination that may be subject to a "corrosion under insulation" aging mechanism, as established in Section E(iii)(b) of LR-ISG-2012-02.

For LRA Table 3.4.2-2-7

Stainless Steel Components Exposed to Steam. In LRA Table 3.4.2-2-7, the applicant stated there are TLAAs for stainless steel orifice, thermowell, tubing, and valve body exposed to steam (internal), which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

For LRA Table 3.4.2-2-9

Carbon Steel Separator Components Exposed to Treated Water. By letter dated December 20, 2013, the applicant revised LRA Table 3.4.2-2-9 and stated that carbon steel separator components exposed to treated water will be managed for loss of material due to erosion by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note H and also cites plant-specific note 403, which states that the aging effect used for this item refers to loss of material due to erosion.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel components exposed to treated water are susceptible to loss of material due to general, pitting, and crevice corrosion and wall thinning. The GALL Report recommends the Water Chemistry and Flow-Accelerated Corrosion Programs. However, the applicant has identified an additional aging mechanism. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.4.2-2-9.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.2.2. The staff finds the applicant's proposal to use the above program to manage loss of material due to erosion acceptable because, as part of its letter dated December 20, 2013, the applicant added specific activities to the Periodic Surveillance and Preventive Maintenance Program to perform visual or other NDE inspections that are capable of managing this mechanism.

For LRA Table 3.4.2-2-10

Stainless Steel Components and Piping Exposed to Steam. In LRA Table 3.4.2-2-10, the applicant stated there are TLAAs for stainless steel orifice, thermowell, tubing, and piping exposed to steam (internal), which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

Nickel Alloy Expansion Joint Exposed to Steam. In LRA Table 3.4.2-2-10, the applicant stated that nickel alloy expansion joints exposed to steam will be managed for cracking and loss of material by the Water Chemistry Control – BWR 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 also noted that the Metals Handbook, Desk Edition, Second Edition (ASM International, 1998) states that nickel and nickel-base alloys generally have very good corrosion resistance in distilled and fresh waters, and the ASM Handbook, Volume 13B, “Corrosion of Nickel and Nickel-Based Alloys” chapter (ASM International, 2005) states that nickel alloys are subject to SCC only in specific environments, such as hot caustic, fluoride, and chloride-containing water environments. Based on this review, 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 applicant’s Water Chemistry Control – BWR Program is documented in SER Section 3.0.3.1.41. The staff finds the applicant’s proposal to manage aging using this program acceptable because the Water Chemistry Control – BWR Program controls contaminants in the condensate system at levels to minimize loss of material and cracking.

In LRA Table 3.4.2-2-10, the applicant stated there is a TLAA for nickel alloy expansion joints exposed to steam (int), which cite generic note G. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.2.2, for this component and material. The staff’s evaluation of the fatigue TLAA for non-Class 1 components is documented in SER Section 4.3.2.2.2.

For LRA Table 3.4.2-2-14

<u>Plastic Tanks Exposed to Treated Water and Indoor Air</u>. By letter dated May 13, 2014, the applicant amended LRA Table 3.4.2-2-14 to include plastic tanks exposed to treated water or indoor air to be managed for changes in material properties by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program or External Surfaces Monitoring Program, respectively. These 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 the applicant addressed plastic components exposed to raw water (internal) and condensation (external) in other AMR items in LRA Table 3.3.2-19-19. The plastic sight glass in LRA Table 3.3.2-19-19 will be managed for a change in material properties by the Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Programs. The staff reviewed the AMPs associated with these items and found them acceptable, as discussed in SER Section 3.3.2.3.19. Based on SER Section 3.3.2.3.19 and the staff’s review of RIS 2012-02, 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 applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Programs are documented in SER Sections 3.0.3.1.25 and 3.0.3.1.17, respectively. The staff finds the applicant’s proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Programs acceptable because the programs include periodic visual inspections that are capable of detecting a change in material properties (e.g., change in clarity, cracking, crazing) prior to a loss of component intended function.

For LRA Table 3.4.2-2-17

Stainless Steel Valves Exposed to Steam. In LRA Table 3.4.2-2-17, the applicant stated there is a TLAA for stainless steel valve body exposed to steam (internal), which cite generic note G. 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 non-Class 1 components is documented in SER Section 4.3.2.

For LRA Table 3.4.2-2-18

Carbon Steel Piping Components Exposed to Raw Water. As modified by letter dated May 13, 2014, LRA Table 3.4.2-2-18 states that carbon steel piping components exposed to raw water will be managed for recurring internal corrosion by the Periodic Surveillance and Preventive Maintenance Program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which states that carbon steel piping components exposed to raw water are susceptible to loss of material and, depending on the system, recommends several different AMPs for managing aging. However, the applicant has identified recurring internal corrosion as an additional aging effect requiring management, as described in LR-ISG-2012-02. The applicant addressed the aging effects identified in the GALL Report for this component, material, and environment combination in other AMR items in LRA Table 3.4.2-2-18.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.2.2. The staff finds the applicant's proposal to use this program to manage recurring internal corrosion acceptable, as documented in SER Section 3.3.2.2.7.

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).

3.4.3 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 section of the SER documents the staff's review of the applicant's AMR results for the structures and component supports components and component groups of:

- containment building
- water control structures
- turbine building, process facilities, and yard structures
- bulk commodities

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 which 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/ 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 due to increased stress levels from settlement	Chapter XI.S2, “ASME 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
Concrete: foundation; subfoundation (3.5.1-2)	Reduction of foundation strength and cracking due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
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 due to elevated temperature (>150 °F general; >200 °F local)	A plant-specific AMP is to be evaluated.	Yes, if temperature limits are exceeded	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
Steel elements (inaccessible areas): drywell shell; drywell head; and drywell shell (3.5.1-4)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	Yes, if corrosion is indicated from the IWE examinations	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to general, pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	Yes, if corrosion is indicated from the IWE examinations	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
Steel elements: torus shell (3.5.1-6)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	Yes, if corrosion is significant. Recoating of the torus is recommende d.	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
Steel elements: torus ring girders; downcomers; steel elements: suppression chamber shell (interior surface) (3.5.1-7)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE”	Yes, if corrosion is significant	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
Pre-stressing system: tendons (3.5.1-8)	Loss of prestress due to relaxation; shrinkage; creep; elevated temperature	Yes, TLAA	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
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 due to fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to stress corrosion cracking	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
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 due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
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 due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
Concrete (inaccessible areas): basemat, concrete (inaccessible areas): dome; wall; basemat (3.5.1-13)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)
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 due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to GGNS (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) due to aggressive chemical attack	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to GGNS (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) due to aggressive chemical attack	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to GGNS (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 due to freeze-thaw	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to GGNS (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 due to expansion from reaction with aggregates	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to GGNS (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) due to corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Concrete (inaccessible areas): basemat; reinforcing steel (3.5.1-22)	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
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) due to corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Containment Inservice Inspection – IWL	Consistent with the GALL Report
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) due to aggressive chemical attack	Chapter XI.S2, "ASME 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/ 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) due to corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	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 due to wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	Containment Inservice Inspection – IWE, Containment Leak Rate, Structures Monitoring, and Periodic Surveillance and Preventive Maintenance	Consistent with the GALL Report (see SER Section 3.5.2.1.2)
Penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell (3.5.1-27)	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Personnel airlock, equipment hatch, CRD hatch (3.5.1-28)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Containment Inservice Inspection – IWE and Containment Leak Rate	Consistent with the GALL Report
Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms (3.5.1-29)	Loss of leak tightness due to mechanical wear of locks, hinges and closure mechanisms	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Pressure-retaining bolting (3.5.1-30)	Loss of preload due to self-loosening	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Pressure-retaining bolting, steel elements: downcomer pipes (3.5.1-31)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.3)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 due to corrosion	Chapter XI.S2, “ASME Section XI, Subsection IWL”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Seals and gaskets (3.5.1-33)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S4, “10 CFR Part 50, Appendix J “	No	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.1.4)
Service Level I coatings (3.5.1-34)	Loss of coating integrity due to 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 due to general, pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Containment Inservice Inspection – IWE and Containment Leak Rate	Consistent with the GALL Report
Steel elements: drywell head; downcomers (3.5.1-36)	Fretting or lockup due to mechanical wear	Chapter XI.S1, “ASME Section XI, Subsection IWE”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements: suppression chamber (torus) liner (interior surface) (3.5.1-37)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Containment Inservice Inspection – IWE and Containment Leak Rate	Consistent with the GALL Report
Steel elements: suppression chamber shell (interior surface) (3.5.1-38)	Cracking due to stress corrosion cracking	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Steel elements: vent line bellows (3.5.1-39)	Cracking due to stress corrosion cracking	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Unbraced downcomers, steel elements: vent header; downcomers (3.5.1-40)	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, “ASME Section XI, Subsection IWE”	No	Not applicable	Not applicable to GGNS (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	Not applicable	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 due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
All groups except Group 6: concrete (inaccessible areas): all (3.5.1-43)	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
All groups: concrete: all (3.5.1-44)	Cracking and distortion due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-45)	Reduction in foundation strength, cracking due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-46)	Reduction of foundation strength and cracking due to 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	Not applicable	See SER Section 3.5.2.2.2
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 due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes,	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Groups 1-5: concrete: all (3.5.1-48)	Reduction of strength and modulus due to elevated temperature (>150 °F general; >200 °F local)	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-49)	Loss of material (spalling, scaling) and cracking due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Groups 6: concrete (inaccessible areas): all (3.5.1-50)	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-51)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Groups 7, 8 - steel components: tank liner (3.5.1-52)	Cracking due to stress corrosion cracking; Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.1.6)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-53)	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes,	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
All groups except 6: concrete (accessible areas): all (3.5.1-54)	Cracking due to expansion from reaction with aggregates	Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.2.2)
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-55)	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete: exterior above- and below-grade; foundation; interior slab (3.5.1-56)	Loss of material due to abrasion; cavitation	Chapter XI.S7, “Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants” or the Federal Energy Regulatory Commission (FERC)/US Army Corp 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 3.5.2.1.7)
Constant and variable load spring hangers; guides; stops (3.5.1-57)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds (3.5.1-58)	Loss of material; loss of form due to 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 Corp 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) due to 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 Corp 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/ 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 (3.5.1-60)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S7, “Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants” or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
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 due to 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 Corp 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 due to 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 Corp of Engineers dam inspections and maintenance programs.	No	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.1.8)
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 due to leaching of calcium hydroxide and carbonation	Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-64)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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, Groups 6: concrete (inaccessible areas): all (3.5.1-65)	Cracking; loss of bond; and loss of material (spalling, scaling) due to 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) due to 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) due to 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 due to stress corrosion cracking	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
High-strength structural bolting (3.5.1-69)	Cracking due to 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	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Masonry walls: all (3.5.1-70)	Cracking due to restraint shrinkage, creep, and aggressive environment	Chapter XI.S5, "Masonry Walls"	No	Masonry Walls and Fire Protection	Consistent with the GALL Report
Masonry walls: all (3.5.1-71)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S5, "Masonry Walls"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Seals; gasket; moisture barriers (caulking, flashing, and other sealants) (3.5.1-72)	Loss of sealing due to 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 due to blistering, cracking, flaking, peeling, physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	Protective Coating Monitoring and Maintenance	Consistent with the GALL Report
Sliding support bearings; sliding support surfaces (3.5.1-74)	Loss of mechanical function due to corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Sliding surfaces (3.5.1-75)	Loss of mechanical function due to corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Sliding surfaces: radial beam seats in BWR drywell (3.5.1-76)	Loss of mechanical function due to corrosion, distortion, dirt, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel components: all structural steel (3.5.1-77)	Loss of material due to 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 (see SER Section 3.5.2.1.9)
Steel components: fuel pool liner (3.5.1-78)	Cracking due to stress corrosion cracking; Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Monitoring of the spent fuel pool water level in accordance with TS 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 Control – BWR	Consistent with the GALL Report (see SER Section 3.5.2.1.10)
Steel components: piles (3.5.1-79)	Loss of material due to corrosion	Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-80)	Loss of material due to general, pitting and crevice corrosion	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring	Consistent with the GALL Report
Structural bolting (3.5.1-81)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-82)	Loss of material due to 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 due to 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 Corp 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 (see SER Section 3.5.2.1.3)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural bolting (3.5.1-84)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-85)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” for BWR water, and Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-86)	Loss of material due to pitting and crevice corrosion	Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-87)	Loss of preload due to self-loosening	Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-88)	Loss of preload due to self-loosening	Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-89)	Loss of material due to boric acid corrosion	Chapter XI.M10, “Boric Acid Corrosion”	No	Not applicable	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 due to general (steel only), pitting, and crevice corrosion	Chapter XI.M2, “Water Chemistry,” for BWR water, and Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Water Chemistry Control – BWR and Inservice Inspection – IWF	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-91)	Loss of material due to general and pitting corrosion	Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Inservice Inspection – IWF	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-92)	Loss of material due to general and pitting corrosion	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.1.11)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-93)	Loss of material due to pitting and crevice corrosion	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Vibration isolation elements (3.5.1-94)	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to GGNS (see SER Section 3.5.2.1.1)
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	Not applicable	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 component supports components:

- Containment Inservice Inspection – IWE
- Containment Inservice Inspection – IWL
- Fire Protection
- Fire Water System
- Inservice Inspection – IWF
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Masonry Wall
- Periodic Surveillance and Preventive Maintenance

- Protective Coating Monitoring and Maintenance
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Structures Monitoring
- Water Chemistry Control – BWR

LRA Tables 3.5.2-1 through 3.5.2-4 summarize AMRs for the structures and component supports 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.

3.5.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.5.1, for items 3.5.1-25, 3.5.1-32, and 3.5.1-76, the applicant stated that the corresponding AMR items in the GALL Report are not applicable because GGNS is a BWR/Mark III reactor design having a reinforced concrete primary containment with a reinforced concrete drywell and wet well lined with carbon steel, and the AMR items in the GALL Report are only applicable to particular components of PWR and BWR MK I designs, and prestressed concrete primary containments. The staff confirmed that the stated AMR items in the GALL Report are only applicable to PWR and BWR MK I designs, and prestressed concrete containments, and are not applicable to the GGNS LRA.

For LRA Table 3.5.1, items 3.5.1-39, 3.5.1-40, and 3.5.1-79, the applicant stated that the corresponding AMR items in the GALL Report are 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 those items in LRA Table 3.5.1, where no further evaluation is recommended, and that the applicant has identified as not applicable but stated that the components are included in the GALL Report recommended program to verify the absence of other aging effects, the staff determined the need for additional information. Therefore, by letter dated October 19, 2012, the staff issued RAI 3.5.1-1 requesting that the applicant provide the technical justification as to why the aging effect does not apply to GGNS or why that aging effect does not require management. The staff also requested, that if the aging effect requires management, the applicant identify which aging management program(s) will be used to manage the identified aging effect during the period of extended operation.

In its response dated November 19, 2012, the applicant revised several LRA Table 3.5.1 items. The staff's evaluation of this response is below.

In response to RAI 3.5.1-1, the applicant revised items 3.5.1-15 and 3.5.1-20, which address concrete (accessible areas): basemat; dome; wall; ring girders; buttresses; containment; wall exposed to water-flowing, to indicate that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation do not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL," to manage this aging effect. The applicant stated that leaching of calcium hydroxide and carbonation is significant only if concrete is exposed to flowing water. The applicant also stated that the concrete containment basemat and primary containment concrete is not exposed to flowing water. The applicant further stated that components are included in the Containment Inservice Inspection – IWL Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Containment Inservice Inspection – IWL Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging. Potential leaching of calcium hydroxide would be detected as water stains on accessible surfaces by the IWL visual examinations.

In response to RAI 3.5.1-1, the applicant revised items 3.5.1-16 and 3.5.1-17, which address concrete (accessible areas): basemat, containment; wall; dome; ring girders; buttresses exposed to ground water/soil and air-indoor, uncontrolled or air-outdoor, to indicate that increase in porosity and permeability; cracking; and loss of material due to aggressive chemical attack do not require management at GGNS. The GALL Report recommends GALL Report AMPs XI.S2, "ASME Section XI, Subsection IWL," or XI.S6, "Structures Monitoring," to manage this aging effect. The applicant stated that concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete with low permeability. The applicant also stated that GGNS does not have an aggressive chemical environment indoors and that the outdoor-air environment is not applicable to the GGNS containment, since it is completely enclosed by an enclosure building. The applicant further stated that components are included in the Containment Inservice Inspection – IWL Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Containment Inservice Inspection – IWL Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging. Potential aggressive chemical attack would be detected by the IWL visual examinations.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-18, which addresses concrete (accessible areas): dome; wall; basemat; ring girders; buttresses exposed to air-outdoor or groundwater/soil, to indicate that loss of material (spalling, scaling) and cracking due to freeze thaw do not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL" to manage this aging effect. The applicant stated that the GGNS primary containment concrete is enclosed by the enclosure building and is not exposed to an air-outdoor environment that would subject the concrete containment to freeze-thaw conditions. The applicant further stated that the components are included in the Containment Inservice Inspection – IWL Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Containment Inservice Inspection – IWL Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging. ASME Section XI, Subsection IWL, Examination Category L-A, requires periodic visual examination of accessible concrete surfaces and would detect any freeze-thaw damage of the concrete containment.

LRA Table 3.5.1, item 3.5.1-19, addresses concrete (accessible areas): concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; concrete (accessible areas): basemat, concrete (accessible areas) containment; wall; basemat, concrete fill-in annulus. The GALL Report recommends GALL Report AMPs XI.S2 "ASME Section XI, Subsection IWL" to manage cracking due to expansion from reaction with aggregates. The applicant stated that the item is not applicable and the listed aging effects do not require management at GGNS. Nonetheless, the components are included in the Containment Inservice Inspection – IWL Program to verify the absence of other aging effects, such as cracking, for components in these listings. The LRA does not provide sufficient information for the staff to verify the non-applicability of this item; therefore, by letter dated August 15, 2012, the staff issued RAI 3.5.1.12-1 requesting the technical justification for the non-applicability of cracking due to expansion from reaction with aggregates as a possible aging effect for the components listed in LRA Table 3.5.1, item 3.5.1-19. The staff's review and acceptance of the applicant's response to RAI 3.5.1.12-1, is documented in SER Section 3.5.2.2.1. The staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these structures and components, as documented in item II.A1.CP-33, II.A2.CP-58, II.B1.2.CP-59, II.B2.2.CP-59, II.B3.1.CP-66, and II.B3.2.CP-60 (SRP-LR Table 3.5-1, item 19).

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-21, which addresses 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 exposed to either an air-indoor uncontrolled or air-outdoor environment, to indicate that cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel does not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL," to manage this aging effect. The applicant stated that for exterior above-grade and interior embedded steel, corrosion is not significant if the steel is not exposed to an aggressive environment (concrete pH less than 11.5 or chlorides greater than 500 ppm) or if the environment surrounding the concrete is not aggressive (pH greater than 5.5, chlorides less than 500 ppm, sulfates less than 1,500 ppm). The applicant also stated that GGNS concrete embedded steel is not exposed to an aggressive environment and concrete is constructed of a dense, well-cured concrete mix with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete with low permeability, designed in accordance with ACI-318 with adequate air-entrainment. The applicant further stated that the components in this listing are included in the Containment Inservice Inspection – IWL Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Containment Inservice Inspection – IWL Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging. Corrosion of embedded steel results in cracking and spalling of concrete and would be detected by the IWL visual examinations.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-22, which addresses concrete (inaccessible areas): basemat; reinforcing steel exposed to either an air-indoor uncontrolled or air-outdoor environment, to indicate that cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel does not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage this aging effect. The applicant stated that for exterior above-grade and interior embedded steel, corrosion is not significant if the steel is not exposed to an aggressive environment (concrete pH less than 11.5 or chlorides greater than 500 ppm) or if the environment surrounding the concrete is not aggressive (pH greater than 5.5, chlorides less than 500 ppm, sulfates less than 1,500 ppm). The applicant also stated that GGNS concrete embedded steel is not exposed to an aggressive environment and concrete is constructed of a dense, well-cured concrete mix with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete with low permeability, designed in accordance with ACI-318 with adequate air-entrainment. The applicant further stated that the components in this listing are included in the Structures Monitoring Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Structures Monitoring Program and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-27, which addresses stainless steel components exposed to either an air-indoor uncontrolled or air-outdoor environment, to indicate that GGNS has a CLB fatigue analysis associated with penetration sleeves and suppression pool liner at the containment wall, and therefore this aging effect is addressed under item 3.5.1-9. The staff reviewed LRA Table 3.5.1, item 3.5.1-9, verified that the applicant does have a CLB fatigue analysis associated with penetration sleeves and suppression pool liner at the containment wall, and that a TLAA has been provided for these components; therefore, the staff finds the applicants claim acceptable. The staff's evaluation of TLAA 4.6, "Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis," is documented in Section 4.6 of this SER.

LRA Table 3.5.1, item 3.5.1-29 addresses the steel personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms exposed to air-indoor uncontrolled or air-outdoor. The GALL Report recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J," programs to manage loss of leak tightness due to mechanical wear of locks, hinges, and closure mechanisms for this component group. The applicant stated that this item is not applicable because locks, hinges, and closure mechanisms are active components and are therefore not subject to an AMR. The applicant also stated that 10 CRF Part 50, Appendix J, and plant TS require testing to ensure leak tightness of airlocks and hatches. The staff evaluated the applicant's claim and noted that Section 3.8.3.1.1, "Drywell Structure," part (d) of the UFSAR states "[t]he equipment hatch is designed to be removed during plant maintenance. During plant operation the drywell equipment hatch is part of the drywell pressure retention boundary and as such uses two compression seals around its periphery to maintain its leak tightness along the mating surfaces. The staff also noted that the NRC by letter dated April 26, 1995, under 10 CFR 50.12(a)(2)(ii), has granted an exemption to GGNS from 10 CFR Part 50, Appendix J, scheduled testing. The exemption allows the applicant to apply specific performance criteria to Type B tests for each containment air lock test. It does not alleviate the applicant from surveillance requirements. The rule states that "Type B Tests" for "[a]ir lock door seals, includ[e] door operating mechanism penetrations which are part of the containment pressure boundary." As stated in 10 CFR 54.35, "Requirements During Term of Renewed License," for the term of a renewed license, licensees shall be subject to and shall continue to comply with all NRC regulations, including those contained in 10 CFR Part 50 and the relevant appendices. It is not clear how the applicant manages wear of the airlock and equipment hatch hardware and mechanisms when assessing leak tightness. By letter dated September 12, 2012, the staff issued RAI 3.5.1-29 requesting the applicant to describe how it plans to manage any aging effects due to wear of locks, hinges, and closure mechanisms.

In its response dated October 9, 2012, the applicant stated that the containment personnel airlocks have hardware components that secure each door in position and perform their functions with moving parts, and therefore, are not subject to aging management review as stated in 10 CFR 54.21. The applicant further stated that the seals which maintain the containment pressure boundary function are managed for aging by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs. The applicant also noted that the airlock and equipment hatch discussed in UFSAR Section 3.8.3.1.1 are located in the drywell and are not part of the containment pressure boundary. Therefore, the components are not subject to ASME Section XI, Subsection IWE or 10 CFR Part 50, Appendix J, inspections, but are inspected under the Structures Monitoring Program. Finally, the applicant explained that the containment equipment hatch is subject to an aging management review and the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs manage the effects of aging on this component. The applicant updated the corresponding items to reflect the changes.

The staff reviewed the applicant’s response and verified that the drywell airlock and equipment hatch discussed in UFSAR Section 3.8.3.1.1 is not part of the containment boundary, and therefore, not subject to ASME Section XI, Subsection IWE or 10 CFR Part 50, Appendix J, inspections. The staff also noted that the pressure retaining components of the containment equipment hatch and the personnel airlock are subject to aging management review and are within the scope of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, Programs. Based on its review, the staff finds the applicant's response acceptable because the applicant verified that all of the pressure retaining components of the containment personnel airlock and containment equipment hatch are being managed by the appropriate GALL Report recommended programs. The staff’s concern in RAI 3.5.1.29-1 is resolved.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-30, which addresses pressure-retaining bolting exposed to any environment, to indicate that GGNS pressure-retaining bolting is associated with securing the equipment hatch and mounting hardware for the personnel airlocks addressed by item 3.5.1-29. The GALL Report recommends GALL Report AMPs XI.S1, “ASME Section XI, Subsection IWE,” and XI.S4, “10 CFR Part 50, Appendix J,” to manage this aging effect. The applicant further stated that the aging effect loss of preload due to self loosening would result in loss of leak tightness of the pressure boundary; therefore, managing the aging effect loss of leak tightness provides reasonable assurance that the intended function of the containment pressure boundary is maintained and the aging effect loss of preload due to self loosening is managed in accordance with item 3.5.1-29. The staff finds the applicant’s response acceptable because the applicant has included these components within the scope of the Containment Inservice Inspection – IWE and Containment Leak Rate Programs which is consistent with the recommendations in the GALL Report.

LRA Table 3.5.1, item 3.5.1-36 addresses steel elements: drywell head and downcomers exposed to air-indoor uncontrolled. The GALL Report recommends GALL Report AMP XI.S1, “ASME Section XI, Subsection IWE,” to manage fretting or lockup due to mechanical wear for this component group. The applicant stated that this item is not applicable because GGNS plant operating experience has not identified fretting or lockup due to mechanical wear for the drywell head, and downcomers are not common to the GGNS Mark III containment. GGNS inspects the drywell head per the requirement of ASME Section XI; and the drywell head is a stationary or fixed component and the spatial distance between connecting components makes it unlikely for fretting and lockup to occur. The staff evaluated the applicant’s claim of a fixed drywell head and noted Section 3.8.3.1.1, “Drywell Structure,” part (d) of the UFSAR states, “at each refueling outage the drywell head is removed to permit unobstructed access to the top of the reactor pressure vessel.” It is not clear if the drywell head is fixed or removable, because a removable drywell head may very well experience mechanical wear. Furthermore the applicant did not state if fleet or industry operating experience has been considered for managing aging effects due to fretting or lockup due to mechanical wear. By letter dated September 12, 2012, the staff issued RAI 3.5.1-36 requesting the applicant to identify whether the drywell head is fixed or removable, and if removable, how the applicant would manage the aging effects due to fretting or mechanical wear associated with its removal during refueling operation.

In its response dated October 9, 2012, the applicant stated that the drywell head is removable; however, it is not part of the containment pressure boundary and therefore is not subject to ASME Section XI, Subsection IWE inspections. The drywell head is inspected under the Structures Monitoring Program. The applicant also stated that plant specific and industry operating experience was reviewed for fretting or lockup due to mechanical wear of the drywell head and none was identified. The applicant updated the discussion portion of LRA Table 3.5.1, item 36, to reflect this information.

The staff reviewed the applicant's response and noted that the drywell head and the drywell mating surfaces are inspected under the Structures Monitoring Program and no wear or fretting has been identified. The staff also verified that the drywell head is not part of the containment pressure boundary and therefore it is appropriate for the component to be inspected under the Structures Monitoring Program. Based on its review, the staff finds the applicant's response acceptable because the appropriate AMP is being used to monitor the component, and the applicant reviewed plant and industry operating experience and found no relevant experience that would indicate the current program is inadequate. The staff's concern in RAI 3.5.1.36-1 is resolved.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-38, which addresses steel elements: suppression chamber shell (interior surface) exposed to an air-indoor uncontrolled environment, to indicate that the stainless steel elements of the GGNS suppression pool are not susceptible to SCC because these elements are not exposed to an aggressive chemical environment or concentration of contaminants, and temperatures are not greater than 140°F. The GALL Report recommends GALL Report AMPs XI.S1, "ASME Section XI, Subsection IWE" and XI.S4, "10 CFR Part 50, Appendix J," to manage this aging effect. The staff finds the applicant's response acceptable because the applicant clarified that these components are not exposed to an environment conducive to SCC, and that the components in this listing are included in the Containment Inservice Inspection – IWE and Containment Leak Rate Program to confirm the absence of the listed aging effect.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-55, which addresses building concrete at locations of expansion and grouted anchors; grout pads for support base plates exposed to an indoor-air uncontrolled or air-outdoor environment, to indicate that reduction in concrete anchor capacity due to local concrete degradation/service induced cracking, or other concrete aging mechanisms will be managed in accordance with items 3.5.1-59 and 3.5.1-66 under the Structures Monitoring and RG 1.127 Programs. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage this aging effect. The staff finds the applicants response acceptable because the reduction in anchor capacity will be managed using both the Structures Monitoring Program, consistent with the GALL Report recommendations, as well as the RG 1.127 Program.

LRA Table 3.5.1, item 3.5.1-57, addresses steel constant and variable load spring hangers, guides, and stops exposed to air-indoor uncontrolled or air-outdoor. The GALL Report recommends GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," to manage loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads for this component group. The applicant stated that this item is not applicable and the listed aging effect does not require management because such failures typically result from inadequate design or events rather than the effects of aging. The applicant further stated that loss of material due to corrosion, which could cause loss of mechanical function, is addressed under items 3.5.1-91 and 3.5.1-92 related to component support members. The staff evaluated the applicant's claim and noted that the components are included in the Inservice Inspection – IWF Program, which, with enhancements, is consistent with the GALL Report. The staff also noted that the Inservice Inspection – IWF AMP uses VT-3 examination to inspect for loss of material due to corrosion, deformation, or misalignment of supports; missing, detached, or loosened support items; improper clearances of guides and stops; and improper hot or cold settings of spring and constant load supports. The staff further noted that the inspections that are part of the Inservice Inspection – IWF Program will adequately detect for loss of mechanical function. The staff finds this acceptable because the effects of aging will be managed so that the intended functions of the constant and variable load spring hangers, guides, and stops will be maintained for the period of extended operation.

LRA Table 3.5.1, item 3.5.1-60, addresses Group 6: concrete (accessible areas) exterior above- and below-grade; foundation exposed to air-outdoor. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants," to manage loss of material (spalling, scaling) and cracking due to freeze-thaw for this component group. The applicant stated that this item is not applicable and the aging effects are not significant for accessible and inaccessible areas. The applicant further stated the these concrete structures are exposed to saturated water conditions near the ground surface; however, the concrete used at GGNS is designed with entrained air content in conformance with ACI-318, and plant experience has not identified any degradation related to freeze-thaw. Nonetheless, the RG 1.127 program will confirm the absence of AERM for GGNS Group 6 concrete components. Therefore, the staff finds the applicant's proposal acceptable because the applicant has included the Group 6: concrete (accessible and inaccessible) areas within the scope of the RG 1.127 program to manage cracking as documented in LRA Table 3.5.1, items 43, 59, and 61.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-63, which addresses Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation exposed to water flowing, to indicate that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation do not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage this aging effect. The applicant stated that leaching of calcium hydroxide and carbonation is significant only if concrete is exposed to flowing water. The applicant also stated that GGNS below-grade exterior reinforced concrete is not exposed to flowing water or an aggressive environment (pH less than 5.5), or to chloride or sulfate solutions beyond defined limits (greater than 500 ppm chloride, or greater than 1,500 ppm sulfate). The applicant further stated that components are included in the Structures Monitoring Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Structures Monitoring Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-64, which addresses Groups 1-3, 5, 7-9: concrete (accessible areas): above- and below-grade; foundation exposed to air-outdoor, to indicate that loss of material (spalling, scaling) and cracking due to freeze-thaw do not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage this aging effect. The applicant stated that inaccessible and accessible concrete areas are designed in accordance with ACI 318, which results in low permeability and resistance to aggressive chemical solutions. The applicant also stated that the components in this listing are included in the Structures Monitoring Program to confirm the absence of the listed aging effects. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Structures Monitoring Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-68, which addresses low-alloy steel high-strength structural bolting (measured yield strength greater than or equal to 150 ksi) exposed to air-indoor, uncontrolled, to indicate that cracking due to stress corrosion cracking does not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," to manage this aging effect. The applicant stated that GGNS does not have high strength bolts that are subject to sustained high tensile stress in a corrosive environment. The applicant also stated that the bolting components in this listing are included in the Inservice Inspection – IWF Program to confirm the absence of the listed aging effect. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Inservice Inspection – IWF Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that NUREG-1801 recommends to manage the effects of aging.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-69, which addresses high-strength structural bolting exposed to indoor-air uncontrolled or air-outdoor, to indicate that cracking due to stress corrosion cracking does not require management at GGNS. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage this aging effect. The applicant stated that GGNS does not have high strength bolts that are subject to sustained high tensile stress in a corrosive environment. The applicant also stated that the bolting components in this listing are included in the Structures Monitoring Program to confirm the absence of the listed aging effect. The staff finds the applicant's response acceptable because the applicant clarified that the components are within the scope of the Structures Monitoring Program, and that the visual inspection activities used to confirm the absence of the potential aging effects are the same visual inspection activities that the GALL Report recommends to manage the effects of aging.

In response to RAI 3.5.1-1, the applicant revised item 3.5.1-71, which addresses all masonry walls exposed to air-outdoor, to indicate the GGNS does not have any masonry walls with the scope of LR in an air-outdoor environment exposed to freeze-thaw conditions. The staff reviewed LRA Section 2.4 and finds the applicant's response acceptable because the applicant does not have any masonry walls exposed to air-outdoor within the scope of license renewal; therefore, this aging effect for these components is not applicable.

LRA Table 3.5.1, items 3.5.1-74 and 3.5.1-75, address sliding support bearings and surfaces made of Lubrite® type material, exposed to air – indoor, uncontrolled or air – outdoor. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage loss of mechanical function due to corrosion, distortion, dirt, debris, overload, and wear for this component group. The applicant stated that this item is not applicable and loss of mechanical function due to the listed mechanisms is not an aging effect. The applicant also stated that such failures typically result from inadequate design or operating events rather than from the effects of aging. The staff confirmed the applicant's claim that properly installed surfaces are practically maintenance-free, noting that SRP-LR ascertains that such plates generally have not shown adverse aging conditions, provided precise tolerances and bearing-specific examinations were maintained during installation. The SRP-LR also states that precautions such as careful installation and clearing out any obstructions during installation ensures that the required tolerances of the bearings are met and reduces the likelihood of functional problems during challenging loading conditions, such as DBAs or safe-shutdown earthquakes. The SRP-LR further affirms that potential aging effects, ranging from malfunctioning, distortion, and dirt accumulation to fatigue under vibratory and cyclic thermal loads, could be managed through the Structures Monitoring and Inservice Inspection – IWF Programs. The staff reviewed the applicant's Structures Monitoring and Inservice Inspection – IWF Programs and confirmed that the programs have their "parameters monitored or inspected," program element enhanced to monitor sliding and bearing surfaces, such as Lubrite® plates, for loss of material due to wear or corrosion, debris, or dirt.

The staff concludes that for LRA items 3.5.1-74 and 3.5.1-75, the applicant's claim is substantiated and 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).

In response to RAI 3.5.1-1, the applicant revised items 3.5.1-81 and 3.5.1-86, which address steel and galvanized steel structural bolting exposed to air-indoor uncontrolled and air-outdoor, to indicate that structural bolts associated with ISI (IWF) components are addressed under bolted connections in item 3.5.1-91. The GALL Report recommends GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," to manage this aging effect. LRA Table 3.5.1, item 3.5.1-91 addresses loss of material due to general and pitting corrosion in support members; welds; bolted connections; and support anchorage to building structures. The staff finds the applicants proposal to manage loss of material in structural bolts using the Inservice Inspection – IWF Program acceptable, because it is consistent with the recommendations in item 3.5.1-91 for the same material and environment combination.

In response to RAI 3.5.1-1, the applicant revised items 3.5.1-84 and 3.5.1-85, which addresses stainless steel structural bolting for Class MC components and stainless steel structural bolting for Class 1, 2 and 3 piping and support components exposed to treated water, to indicate the GGNS does not have this component, material, and environment combination. The staff reviewed the applicant's response and finds it acceptable because this item is not applicable in the absence of this component, material, and environment combination.

LRA Table 3.5.1, items 3.5.1-87, addresses structural bolting exposed to any environment. The GALL Report recommends GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," to manage loss of preload due to self-loosening for this component group. The applicant stated that this item is not applicable and the listed aging effects do not require management at GGNS. The applicant did not provide any further discussion. The staff determined it needed more information to complete its review. Therefore, by letter dated June 27, 2012, the staff issued RAI 3.5.1.87-1 requesting that the applicant explain why loss of preload is not an aging effect for structural bolting within the scope of license renewal, or to provide an acceptable AMP to manage the loss of preload during the period of extended operation. The applicant responded by letter dated July 25, 2012, stating that vibration, flexing of the joint, cyclic shear loads, thermal cycles, and other conditions can cause self-loosening of a fastener; however, these causes are minor contributors in structural steel and steel component threaded connections and are eliminated by initial preload bolt torquing. The applicant further stated that GGNS uses site procedures and manufacturer recommendations to provide guidance for proper torquing of nuts and bolts used in structural applications, and operating experience has not shown self-loosening of structural bolting at GGNS. The staff finds the response acceptable because the applicant will include structural bolting in the "Inservice Inspection – IWF" AMP, which has been enhanced to include inspection of structural bolting (ASTM A325, ASTM F1852, and ASTM A490 bolts), in part, for loose or missing nuts, and loss of preload. This enhancement, once implemented, will ensure that loss of preload will be managed for structural bolts for the period of extended operation. The staff's evaluation of the applicant's Inservice Inspection – IWF Program is documented in SER Section 3.0.3.1.23.

LRA Table 3.5.1, item 3.5.1-88 addresses structural bolting exposed to any environment. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage loss of preload due to self-loosening for this component group. The applicant stated that this item is not applicable and the listed aging effects do not require management at GGNS. The applicant did not provide any further discussion. The staff determined additional information was needed to complete its review. Therefore, by letter dated June 27, 2012, the staff issued RAI 3.5.1.87-1 requesting that the applicant explain why loss of preload due to self-loosening is not an aging effect for structural bolting within the scope of license renewal, or to provide an acceptable AMP to manage the loss of preload during the period of extended operation. The applicant responded by letter dated July 25, 2012, stating that vibration, flexing of the joint, cyclic shear loads, thermal cycles and other conditions can cause self-loosening of a fastener; however, these causes are minor contributors in structural steel and steel component threaded connections and are eliminated by initial preload bolt torquing. The applicant further stated that GGNS uses site procedures and manufacturer recommendations to provide guidance for proper torquing of nuts and bolts used in structural applications, and operating experience has not shown self-loosening of structural bolting at GGNS. The staff finds the response acceptable because the applicant will include structural bolting in the Structures Monitoring Program, which has been enhanced to include inspection of structural bolting for missing nuts for structural connections. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40.

For LRA Table 3.5.1, item 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 that these items are not applicable to GGNS, which is a BWR.

LRA Table 3.5.1, item 3.5.1-94 addresses nonmetallic (e.g., rubber) vibration isolation elements exposed to air-indoor, uncontrolled or air-outdoor. The GALL Report recommends GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," to manage reduction or loss of isolation function due to radiation hardening, temperature, humidity, and sustained vibratory loading for this component group. The applicant stated that this item is not applicable and no vibration isolation elements at GGNS are in scope and subject to an AMR. The staff reviewed the Inservice Inspection – IWF Program and noted that in LRA Section B.1.24, the applicant stated that it is enhancing the "parameters monitored or inspected" program element to monitor elastomeric vibration elements for cracking, loss of material, and hardening. The staff also noted that in LRA Section A.1.42, the applicant stated that the Structures Monitoring Program will be enhanced such that vibration isolators will receive augmented inspections by feel or touch to detect hardening if the vibration isolation function is suspect. The staff found these enhancements to be inconsistent with the claim that there are no vibration isolation elements in scope for license renewal, and thus needed more information to complete its review. Therefore, by letter dated August 21, 2012, the staff issued RAI 3.5.1.94-1 requesting that the applicant resolve this discrepancy.

The applicant responded by letter dated September 13, 2012, and stated that while there are vibration isolation elements within the scope of license renewal, none of those in scope are non-metallic. The vibration isolation elements that are within the scope of license renewal are integral parts of structural support assemblies and are included in LRA Table 2.4-4 as bulk commodities subject to aging management review and LRA Table 3.5.2-4, where they are included with the items for component and piping supports; and component and piping supports for ASME Class 1, 2, 3, and MC. The applicant also stated that the aging effects for those components are managed by the Structures Monitoring Program and ISI-IWF aging management programs. The applicant revised its enhancement to the ISI-IWF "parameters monitored or inspected" program element to reflect this issue.

The staff evaluated the applicant's claim and finds it acceptable because the applicant does not have non-metallic vibration isolation elements within the scope of license renewal and is therefore not required to include those components in its aging management program. The vibration isolation elements that are within the scope of license renewal are being managed by the appropriate AMPs.

3.5.2.1.2 Loss of Sealing Due to Wear, Damage, Erosion, Tear, Surface Cracks, or Other Defects

LRA Table 3.5.1, item 3.5.1-26 addresses elastomer moisture barriers (caulking, flashing, and other sealants) exposed to an air-indoor uncontrolled environment that will be managed for loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects; however, the applicant stated that loss of sealing is a consequence of the aging effects cracking and change in material properties. For the AMR item that cites generic note E, the LRA credits the Containment Leak Rate Program to manage the cracking and change in material properties for elastomer containment building electrical penetration seals and sealant. The GALL Report recommends using GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S1 recommends using visual examinations (general visual, VT-3, and VT-1) of moisture barriers for wear, damage, erosion, tear, surface cracks, and other defects that permit intrusion of moisture into the inaccessible areas of pressure-retaining surfaces of the metal containment shell or liner.

The staff's evaluation of the Containment Leak Rate Program is documented in SER Section 3.0.3.1.14. The staff noted that the Containment Leak Rate Program proposes to manage the aging of elastomer containment building electrical penetration seals and sealants through performance of containment leakage rate tests at frequencies that comply with the requirements of 10 CFR Part 50, Appendix J, and Option B. In its review of components associated with item 3.5.1-26, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Containment Leak Rate Program unacceptable because the Containment Leak Rate Program is a performance monitoring program that monitors parameters related to leakage rates and does not by itself provide information that would indicate aging degradation has initiated. The staff is unable to determine that visual examinations are performed of elastomer containment building electrical penetration seals and sealants to manage aging in the form of cracking or change in material properties, or how the Containment Leak Rate Program will evaluate change in material properties. By letter dated June 27, 2012, the staff issued RAI 3.5.2.1-1 requesting that the applicant describe how the applicant's Containment Leak Rate Program meets the recommendations in GALL Report item II.B4.CP-40 related to aging management of cracking and change in material properties of elastomer containment building electrical penetration seals and sealant.

In its response dated July 25, 2012, the applicant stated that this item addresses containment building electrical penetration seals and gaskets and that LRA Table 3.5.2-1 has been revised so that the appropriate NUREG-1801 item is identified (II.B4.CP-41), Table 1 item is changed to 3.5.1-33, and the Note "E" has been changed to Note "A" indicating consistency with NUREG-1801.

The staff finds the applicant's response acceptable because the component, material, environment, aging effect, and AMP are now consistent with the GALL Report. The staff's concern described in RAI 3.5.2.1-1 is resolved.

LRA Table 3.5.1, item 3.5.1-26 addresses elastomer moisture barriers (caulking, flashing, and other sealants) exposed to an air-indoor uncontrolled environment that will be managed for loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects; however, the applicant stated that loss of sealing is a consequence of the aging effects cracking and change in material properties. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring Program to manage the aging effects for elastomer containment building moisture barriers. The GALL Report recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S1 recommends using visual examinations (general visual, VT-3, and VT-1) of moisture barriers for wear, damage, erosion, tear, surface cracks, and other defects that permit intrusion of moisture in the inaccessible areas of pressure-retaining surfaces of the metal containment shell or liner.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of moisture barriers through performance of visual inspections at 5-year intervals by qualified personnel using acceptance criteria provided in industry codes, standards, and guidelines including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-96. In its review of components associated with item 3.5.1-26, 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 hardening, shrinkage, and loss of sealing of elastomers will be managed through visual inspections conducted by qualified personnel at intervals not to exceed 5 years in accordance with recommendations in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-02. The applicant's AMP meets the recommendations in GALL Report item II.B4.CP-40 and therefore is consistent with GALL Report AMP XI.S1 "ASME Section XI, Subsection IWE," which is identified as the appropriate AMP in the GALL Report.

LRA Table 3.5.1, item 3.5.1-26 addresses elastomer moisture barriers (caulking, flashing, and other sealants) exposed to an air-indoor uncontrolled environment that will be managed for loss of sealing due to wear, damage, erosion, tear, surface, cracks, or other defects; however, the applicant stated that loss of sealing is a consequence of the aging effects cracking and change in material properties. For the AMR items that cite generic note E, the LRA credits the Periodic Surveillance and Preventive Maintenance Program to manage the cracking and change in material properties of elastomer upper containment pool gates rubber gasket/seal. The GALL Report recommends AMP XI.S1, "ASME Section XI, Subsection IWE," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S1 recommends using visual examinations (general visual, VT-3, and VT-1) of moisture barriers for wear, damage, erosion, tear, surface cracks, and other defects that permit intrusion of moisture in the inaccessible areas of pressure-retaining surfaces of the metal containment shell or liner.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.2.2. The staff noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage aging of elastomer upper containment pool gates rubber gasket/seal through visual inspections and manually flexing the rubber gasket/seal for upper containment pool gates to verify the absence of cracks and significant changes of material properties. The Periodic Surveillance and Preventive Maintenance Program is an existing program that manages aging effects not managed by other AMPs, including loss of material, cracking, and change in material properties, and there is no corresponding GALL Report AMP. In its review of components associated with item 3.5.1-26, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because the program visually inspects and manually flexes the rubber gasket/seal for the upper containment pool gates at least once every 5 years to verify the absence of cracks and significant change in material properties. The applicant's AMP meets the recommendations in GALL Report item II.B4.CP-40 and therefore is consistent with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," which is identified as the appropriate AMP in the GALL Report.

The staff concludes that for LRA items 3.5.1-26, 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).

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

LRA Table 3.5.1, item 3.5.1-31 addresses pressure-retaining bolting, and steel elements: downcomer pipes exposed to a fluid environment that will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the Inservice Inspection – IWF Program and the Water Chemistry Control – BWR Program to manage the aging effect for carbon steel quencher supports. The GALL Report recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE Program," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S1 recommends using visual examinations of non-coated surfaces to detect evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities for components of steel containments and steel liners of concrete containments.

The staff's evaluation of the Inservice Inspection – IWF Program and the Water Chemistry Control - BWR Program is documented in SER Sections 3.0.3.1.23 and 3.0.3.1.41, respectively. The staff noted that the Inservice Inspection – IWF Program proposes to manage the aging of carbon steel quencher supports through visual examinations to identify loss of material due to corrosion or wear that reduces the load-bearing capacity of the component support. The staff also noted that the Water Chemistry Control – BWR Program proposes to manage the aging of carbon steel quencher supports through monitoring and control of water chemistry using EPRI water chemistry guidelines. In its review of components associated with item 3.5.1-31, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inservice Inspection – IWF Program and the Water Chemistry Control – BWR Program acceptable because loss of material will be managed through periodic visual examinations (VT-3) performed by qualified personnel and through monitoring and control of water chemistry using EPRI water chemistry guidelines. The applicant's VT-3 examinations for loss of material are consistent with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE Program," which is identified as the appropriate AMP in the GALL Report.

The staff concludes that for LRA items 3.5.1-31, 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).

LRA Table 3.5.1, item 3.5.1-83 addresses structural bolting exposed to a fluid environment that will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring Program to manage the aging effect for carbon steel anchorage/embedments, component and piping supports, and structural bolting. The GALL Report recommends GALL Report AMP XI.S7 “Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” to ensure that these aging effects are adequately managed. GALL Report AMP XI.S7 recommends monitoring and visual inspection at intervals not to exceed 5 years for indications of loss of material in bolted connections and other structural bolting.

The staff’s evaluation of the applicant’s Structures Monitoring Programs documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of carbon steel anchorage/embedments, components and piping supports, and structural bolting through the use of visual inspections at 5-year intervals using qualified personnel and acceptance criteria based on information provided in industry codes, standards, and guidelines including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-96. In its review of components associated with item 3.5.1-83 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 loss of material will be managed through visual inspections conducted by qualified personnel at intervals not to exceed 5 years, in accordance with recommendations in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-02. The applicant’s AMP meets the recommendations in the GALL Report item III.A6.TP-221 and therefore is consistent with GALL Report AMP XI.S7 “Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” which is identified as the appropriate AMP in the GALL Report.

The staff concludes that for LRA item 3.5.1-83, 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).

3.5.2.1.4 Loss of Sealing Due to Wear, Damage, Erosion, Tear, Surface Cracks, or Other Defects

LRA Table 3.5.1, item 3.5.1-33 addresses seals and gaskets that will be managed for loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects. The LRA states that these items are associated with components outside of containment. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring Program to manage the aging effect for roof membranes exposed to outdoor air, and seals and gaskets (doors, manways, and hatches) exposed to uncontrolled indoor air. The GALL Report recommends GALL Report AMP XI.S4, “10 CFR Part 50, Appendix J,” to ensure that these aging effects are adequately managed. GALL Report AMP XI.S4 recommends using containment leak rate testing to manage aging for containment pressure boundary components, including seals and gaskets.

The staff noted that item 3.5.1-33 states, "GGNS items referring to seals and gaskets are associated with components outside containment and are managed by the Structures Monitoring Program for cracking and change in material properties." The staff also noted that, although item 3.5.1-33 states that the seals and gaskets are "outside containment," the seals and gaskets can be outside containment and still be associated with the containment penetration boundary. By letter dated June 20, 2012, the staff issued RAI 3.5.1.33-1 requesting that the applicant state whether any of the seals and gaskets (doors, manways, and hatches) which are included in LRA Table 3.5.2-4 and cite item 3.5.1-33 are associated with the containment penetration function. Furthermore if they are, the staff asked the applicant to state the basis for using the Structures Monitoring Program in lieu of the Containment Leak Rate Program, or to revise the LRA to reflect that the Containment Leak Rate Program will be used to manage their aging.

In its response dated July 19, 2012, the applicant stated that, "[t]he seals and gaskets (doors, manways, and hatches) that are included in LRA Table 3.5.2-4 and cite item 3.5.1-33 are not associated with containment penetrations."

The staff finds the applicant's response acceptable because utilization of GALL Report AMP XI.S4 is not appropriate for items that are not associated with containment penetrations, and the visual inspections conducted by the Structures Monitoring Program are sufficient to detect wear, damage, erosion, tear, surface cracks, or other defects. The staff's concern described in RAI 3.5.1.33-1 is resolved.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of roof membranes exposed to outdoor air, and seals and gaskets (doors, manways, and hatches) exposed to uncontrolled indoor air through the use of periodic visual inspections to detect hardening, shrinkage, and loss of sealing. The staff noted that the Structures Monitoring Program includes an enhancement to perform physical manipulation of vibration isolaters if the vibration isolation function is suspect; however, neither the program nor the implementing procedures contain a requirement to augment the visual examinations with physical manipulation for roof membranes, and seals and gaskets (doors, manways, and hatches). In addition the staff noted that the "detection of aging effects" program element of GALL Report AMPs XI.M36 and XI.M38 recommend that 10 percent of available surface area of flexible polymeric components be manipulated; however neither the Structures Monitoring Program nor the implementing procedures contain a requirement to conduct this sample size inspection. By letter dated June 20, 2012, the staff issued RAI 3.5.1.33-2 requesting that the applicant enhance the Structures Monitoring Program to include physical manipulation of 10 percent of the available surface area of flexible roof membranes, and seals and gaskets (doors, manways, and hatches), or state the reason why there is a reasonable assurance that the components will meet their CLB intended function(s) absent physical manipulation.

In its response dated July 19, 2012, the applicant stated that, "[t]he Structures Monitoring Program will be enhanced to include instructions to augment the visual examinations of roof membranes, and seals and gaskets (doors, manways, and hatches) with physical manipulation of at least 10 percent of available surface area." The staff noted that the applicant revised LRA Sections A.1.42 and B.1.42 to reflect the new enhancement.

In its review of components associated with item 3.5.1-33, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program and its response to RAI 3.5.1.33-2 acceptable because the Structures Monitoring

Program conducts periodic visual examinations enhanced by physical manipulation of at least 10 percent of the available surface area of flexible polymeric materials and age managing of seals; gasket; moisture barriers (caulking, flashing, and other sealants) with the Structures Monitoring Program is consistent with the GALL Report. The staff's concern described in RAI 3.5.1.33-2 is resolved.

During its evaluation of this item, the staff reviewed UFSAR Chapters 6 and 9. This review resulted in the following two RAIs:

The staff noted that UFSAR Table 6.2-49 includes a footnote that applies to penetrations associated with the equipment hatch, personnel locks, fuel transfer tube, and guard pipe inspection ports that states that the, "[p]enetration is sealed by a blind flange or door with double O-ring seals, double expandable seals, double gasket seals, or a weld. These seals are leakage rate tested by pressurizing between the seals or gaskets. Because the guard pipe inspection ports inboard seal is a weld, Type B testing is not required." It was not clear to the staff whether the seals or gaskets associated with the fuel transfer tube and guard pipe inspection ports are being managed by the Containment Leak Rate Program or whether they are not considered long-lived passive items. By letter dated June 20, 2012, the staff issued RAI 3.5.1.33-1 requesting that the applicant state how the seals or gaskets associated with the fuel transfer tube and guard pipe inspection ports are being managed, or state that they are not considered to be long-lived passive items.

In its response dated July 19, 2012, the applicant stated that there are no seals or gaskets associated with the guard pipe inspections ports because sealing of this component is accomplished by welding. The applicant also stated that, "[t]he seal for the fuel transfer tube is included in LRA Table 3.5.2-1, as part of the AMR item for "rubber seal for airlock doors, equipment hatch." The applicant amended LRA Table 3.5.2-1 to include the wording, "fuel transfer tube" within the description of the AMR item for rubber seal for airlock doors, equipment hatch. The staff noted that this item is being managed for cracking and change in material properties by the Containment Inservice Inspection – IWE and Containment Leak Rate Programs and cites item 3.5-1-26 and generic note B. The staff also noted that SRP-LR Table 3.5-1, item 3.5.1-26 states that the Chapter XI.S1, "ASME Section XI, Subsection IWE," should be used to manage loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects.

The staff finds the applicant's response acceptable because the visual examination and leak rate testing performed as part of the Containment Inservice Inspection – IWE and Containment Leak Rate Programs are capable of detecting cracking and change in material properties of elastomeric seals. The staff noted that typical visual inspections of elastomeric materials are accompanied by physical manipulation to detect hardening or loss of strength; however, the pressure testing included in the Containment Leak Rate will demonstrate leak tightness that is only achievable if the elastomeric materials have not hardened or lost strength. The staff's concern described in RAI 3.5.1.33-1 is resolved.

The staff noted that UFSAR Chapter 9, page 769, 9A.5.2.3n, states, "[t]he blowout shaft, Fire Zone 1A124, consists of the remaining horizontal separation distance, which contains concrete joint sealant (Rodofoam 11)." It is not clear to the staff whether this concrete joint sealant fulfills a license renewal intended function. The staff reviewed the LRA and did not identify an AMR item that corresponds to the description of this material. By letter dated June 20, 2012, the staff issued RAI 3.5.2.4-2 requesting that the applicant (a) state whether the concrete joint sealant (Rodofoam II) has a license renewal intended function, (b) if it does have a license renewal intended function, state whether it is a long-lived passive component, and (c) if both of these responses are positive, state what AMR item includes this item.

In its response dated July 19, 2012, the applicant stated that "[t]he concrete joint sealant (Rodofoam II) has license renewal intended functions of "fire barrier" and "support for Criterion (a)(1) equipment" (SSR). The concrete joint sealant (Rodofoam II) is a long-lived passive component subject to AMR as indicated in LRA Table 3.5.2-4 by component "Seismic isolation joint." As shown in Table 3.5.2-4, the Fire Protection Program is credited to manage aging effects."

The staff finds the applicant's response acceptable because the applicant stated that the item is in-scope, and it is being age managed by the Fire Protection Program, which is consistent with the GALL Report items A-19 and A-20. The staff's concern described in RAI 3.5.2.4-2 is resolved.

The staff concludes that for LRA item 3.5.1-33, 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).

3.5.2.1.5 Loss of Material Due to General (Steel Only), Pitting, and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1-78, as revised by letter dated June 6, 2012, addresses steel components: fuel pool liner exposed to a fluid environment which will be managed for loss of material due to pitting and crevice corrosion. The staff noted that SRP item 3.5.1-78 also states stainless steel in a treated water environment is susceptible to stress corrosion cracking. However, the staff reviewed UFSAR Section 6.2 and noted that the suppression pool temperature is at the maximum for normal conditions, which is 95°F, and is below the 140°F (60°C) threshold for stainless steel in treated water as defined in GALL Report Chapter IX.D. For the AMR items that cite generic note E, the LRA credits AMP XI.S6, "Structures Monitoring" to manage loss of material for stainless steel weir wall liner plates. The GALL Report recommends AMP XI.M2, "Water Chemistry" to ensure that these aging effects are adequately managed. GALL Report AMP XI.M2 recommends periodic monitoring of treated water in order to minimize loss of material or cracking.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of stainless steel weir wall liner plates through periodic visual examinations. The staff also notes, that in its response to RAI B.2.1.13-4, the applicant stated that because the Structures Monitoring program specifies opportunistic inspection, the submerged portion of the weir wall is typically inspected during the ASME Section XI, Subsection IWE inspections. Additional information regarding the inspection of the weir wall liner plates is addressed in SER Section 3.0.3.1.12. In its review of components associated with item 3.5.1-78, 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 surfaces of the stainless steel weir wall liner plates are periodically visually inspected for loss of material due to pitting and crevice corrosion.

The staff concludes that for LRA items 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 will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.6 Loss of Material Due to Pitting and Crevice Corrosion, and Cracking Due to Stress Corrosion Cracking

LRA Table 3.5.1, item 3.5.1-52, addresses Groups 7,8 – steel components: tank liner exposed to a fluid environment that will be managed for loss of material due to pitting or crevice corrosion and cracking due to SCC. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring Program to manage the loss of material due to pitting and crevice corrosion aging effect for containment building and RPV pedestal stainless steel sump liners and penetrations; water control structures basin debris stainless steel screen and grating, stainless steel cooling tower fill, and fan stack stainless steel grating; and turbine building, process facilities, and yard structures stainless steel sump liners. The GALL Report recommends using a plant-specific AMP to ensure that these aging effects are adequately managed. The staff noted that the Structures Monitoring Program proposes to manage the aging of containment building and RPV pedestal stainless steel sump liners and penetrations; water control structures basin debris stainless steel screen and grating, stainless steel cooling tower fill, and fan stack stainless steel grating; and turbine building, process facilities, and yard structures stainless steel sump liners through the use of visual inspections at 5-year intervals using qualified personnel and acceptance criteria based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R- 96.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. In its review of components associated with item 3.5.1-52, for which the applicant cited generic note E, the staff noted that item 3.5.1-52 addresses both loss of material due to pitting and crevice corrosion, and cracking due to stress corrosion cracking. However, in LRA Section 3.5.2.2.2.4, the applicant states that there are no tanks with stainless steel liners in the structural scope of license renewal. The applicant has indicated that the corresponding GALL Report items can be compared to the stainless steel liners of other components, such as reactor cavity and containment sump, which are exposed to a fluid environment and may be subject to loss of material. The staff also notes that the applicant stated the fluid temperatures, for which these components are exposed to, are below the threshold for stress corrosion cracking. Therefore, the staff finds the applicant's proposal to manage loss of material due to pitting and crevice corrosion using the Structures Monitoring Program is acceptable because loss of material will be managed through visual inspections conducted by qualified personnel at intervals not to exceed 5 years in accordance with recommendations in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-02. The applicant's visual examinations for loss of material under the Structures Monitoring program are consistent with the recommendations in the GALL Report that identifies use of a plant-specific aging management program.

LRA Table 3.5.1, item 3.5.1-52 addresses Groups 7, 8 - steel components: tank liner exposed to a fluid environment that will be managed for loss of material due to pitting or crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry Control – BWR Program to manage the loss of material due to pitting and crevice corrosion for containment building upper containment pool stainless steel liner plate and grating, and stainless steel spent fuel pool storage racks. The GALL Report recommends using a plant-specific AMP to ensure that these aging effects are adequately managed. The staff noted that the Water Chemistry Control - BWR Program proposes to manage the aging of containment building upper containment pool stainless steel liner plate and grating, and stainless steel spent fuel pool storage racks through monitoring and control of water chemistry using EPRI water chemistry guidelines.

The staff's evaluation of the applicant's Water Chemistry Control – BWR Program is documented in SER Section 3.0.3.1.41. In its review of components associated with item 3.5.1-52, for which the applicant cited generic note E, the staff determined the need for additional information. Therefore, by letter dated September 12, 2012, the staff issued RAI 3.5.1.52-3 requesting the applicant explain how cracking due to stress corrosion cracking of these components will be managed to meet the recommendations of GALL Report items III.A7.T-23 and III.A8.T-23.

In its response dated October 9, 2012, the applicant stated that,

> For stress corrosion cracking (SCC) of stainless steel material in a fluid environment (treated water), the temperature of the fluid environment must be > 140° F (> 60° C) [NUREG-1801, IX.D Environments, discussed temperature thresholds for SCC]. The Grand Gulf Nuclear Station (GGNS) structural stainless steel components identified in this RAI are exposed to a fluid environment (treated water) at temperatures < 140° F (< 60° C). Therefore, cracking due to SCC is not an aging effect requiring management.

The staff noted that the applicant also revised the LRA to reference Table 3.5.1, item 3.5.1-78 and GALL Report item III.A5.T-14.

The staff reviewed the applicant's response, and finds that because the components in this listing are not exposed to fluid environment (treated water) and temperatures greater than 140° F (60° C), stress corrosion cracking for these components would not be a concern. Additionally, the staff notes that the applicant revised the LRA to reference Table 3.5.1, item 3.5.1-78, which appropriately represents the component, material, and environment combination, and is consistent with GALL Report item III.A5.T-14. The staff's concern described in RAI 3.5.1.52-3 is resolved.

The staff finds the applicant's proposal to manage loss of material due to pitting and crevice corrosion using the Water Chemistry Control - BWR Program acceptable because loss of material will be managed by the Water Chemistry Control - BWR Program through monitoring and control of water chemistry using EPRI water chemistry guidelines. Additionally, the spent fuel pool water level is monitored in accordance with TS, and monitoring leakage from the leak test channels will continue during the period of extended operation, which is consistent with the GALL Report recommendations and therefore, acceptable.

The staff concludes that for LRA items 3.5.1- 52, 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).

3.5.2.1.7 Loss of Material Due to Abrasion and Cavitation

LRA Table 3.5.1, item 3.5.1-56 addresses concrete: exterior above- and below-grade; foundation; and interior slab exposed to a fluid environment that will be managed for loss of material due to abrasion and cavitation. For the AMR item that cites generic note E, the LRA credits the Structures Monitoring Program to manage the aging effect for concrete support pedestals. The GALL Report 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 Corp of Engineers dam inspections and maintenance programs to ensure that these aging effects are adequately managed. GALL Report AMP XI.S7 recommends monitoring and visual inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage to manage the aging of these items.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of concrete support pedestals through the use of visual inspections at 5-year intervals using qualified personnel and acceptance criteria based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-96. In its review of components associated with item 3.5.1-56 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 loss of material will be managed through visual inspections conducted by qualified personnel at intervals not to exceed 5 years in accordance with recommendations in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-02. The applicant's AMP meets the recommendations in the GALL Report item III.A6.T-20 and therefore is consistent with GALL Report AMP XI.S7 "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," which is identified as the appropriate AMP in the GALL Report.

The staff concludes that for LRA item 3.5.1-56, 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).

3.5.2.1.8 Loss of Material and Change in Material Properties Due to Weathering, Chemical Degradation, Insect Infestation, Repeated Wetting and Drying, and Fungal Decay

LRA Table 3.5.1, item 3.5.1-62 addresses Group 6: wooden piles and sheeting exposed to air – outdoor or soil environments that will be managed for loss of material and change in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, and fungal decay. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring Program to manage the aging effect for treated wooden utility poles and towers. The GALL Report recommends GALL Report AMP XI.S7, Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S7 recommends monitoring and visual inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of wooden utility poles and towers through the use of visual inspections at 5-year intervals using qualified personnel and acceptance criteria based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-96. In its review of components associated with item 3.5.1-62, 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 meets recommendations in the GALL Report item III.A6.TP-223 in that its visual inspection requirements are consistent with GALL

Report AMP XI.S7, “Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” which is identified as the appropriate AMP in the GALL Report.

The staff concludes that for LRA item 3.5.1-62, 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).

3.5.2.1.9 Loss of Material Due to Corrosion

LRA Table 3.5.1, item 3.5.1-77 addresses steel components: all structural steel exposed to air – indoor uncontrolled environment that will be managed for loss of material due to corrosion. For the AMR item that cites generic note E, the LRA credits the Structures Monitoring Program to manage the aging effect for carbon steel monorails. The GALL Report recommends GALL Report AMP XI.S6, “Structures Monitoring Program,” and 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. GALL Report AMP XI.S6 recommends using periodic visual inspections by qualified personnel, at a frequency not to exceed 5 years, to monitor steel components for loss of material.

The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the Structures Monitoring Program proposes to manage the aging of carbon steel monorails through the use of visual inspections at 5-year intervals using qualified personnel and acceptance criteria based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-96. In its review of components associated with item 3.5.1-77 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 loss of material will be managed through visual inspections conducted by qualified personnel at intervals not to exceed 5 years in accordance with recommendations in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R-02. The applicant’s AMP meets the recommendations in the GALL Report item III.A1.TP-302 and therefore is consistent with GALL Report AMP XI.S6,”Structures Monitoring Program,” which is identified as the appropriate AMP in the GALL Report.

The staff concludes that for LRA item 3.5.1-77, 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).

3.5.2.1.10 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1-78 addresses steel fuel pool liner components that will be managed for loss of material due to pitting and crevice corrosion. The LRA states that cracking due to SCC is not an aging effect requiring management because there are no in-scope stainless steel fuel pool components exposed to treated water greater than 60 °C (140 °F). The staff noted that the GALL Report recommends GALL Report AMP XI.M2, “Water Chemistry,” and monitoring of the spent fuel pool water level and leakage from the leak chase channels to ensure that these aging effects are adequately managed.

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 9.1.3.2 states that the spent fuel pool water is normally maintained below 140 °F, the threshold for SCC defined in the GALL Report Table IX.D, and therefore, finds the applicant's claim acceptable.

During its review of components associated with item 3.5.1-78, for which the applicant cited generic note A, the staff noted that the LRA credits the Water Chemistry Control – BWR Program, the One-Time Inspection Program (as cited in plant-specific note 504), and monitoring of the spent fuel pool water level to manage cracking for the spent fuel pool liner and gate. However, the staff also noted that LRA item 3.5.1-78 states that loss of material is the only applicable aging effect and monitoring of leakage in the leak chase channels is an additional aging management activity. The staff further noted that the applicant credits monitoring of the spent fuel pool water level as an aging management activity for the spent fuel storage racks. By letter dated May 24, 2012, the staff issued RAI 3.5.1.78-1 requesting that the applicant (a) clarify which aging effects are applicable to the spent fuel pool liner and gate; (b) remove monitoring of the spent fuel pool water level as an aging management activity for the spent fuel storage racks, or justify why this activity is capable of managing degradation of the racks; (c) resolve a discrepancy between LRA item 3.5.1-78 and the associated ARM items regarding the use of the One-Time Inspection Program; and (d) revise the AMR items associated with spent fuel pool liner and gate to include monitoring of leakage in the leak chase channels.

In its response dated June 22, 2012, the applicant (a) revised the AMR item for the spent fuel pool liner and gate to state that loss of material is the only applicable aging effect; (b) revised the AMR item for the spent fuel storage racks to delete monitoring of pool water level as an aging management activity; (c) clarified that the One-Time Inspection Program is used to verify the effectiveness of the Water Chemistry program for items associated with LRA item 3.5.1-78, although the description of this item in LRA Table 3.5.1 does not discuss this activity; and (d) revised the AMR item associated with the spent fuel pool liner plate and gate to state that monitoring of leakage from the leak chase channels is an aging management activity for these structures.

The staff finds the applicant's response acceptable because the management of loss of material for the spent fuel pool liner and gate with the Water Chemistry Control – BWR Program and monitoring of water level and leakage is consistent with SRP-LR Table 3.5-1, item 78, given that cracking is not an expected aging effect for water environments below 60 °C (140 °F). Also, the use of the One-Time Inspection Program to verify the effectiveness of water chemistry controls provides additional assurance that degradation of spent fuel pool liner and gate will be identified prior to loss of intended functions. Further, the management of the spent fuel storage racks for loss of material with the Water Chemistry Control – BWR and One-Time Inspection Programs is consistent with the guidance in the GALL Report item VII.A2.A-98, as revised by license renewal interim staff guidance, LR-ISG-2011-01. The staff's concern described in RAI 3.5.1.78-1 is resolved.

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).

3.5.2.1.11 Loss of Material Due to General and Pitting Corrosion

LRA Table 3.5.1, item 3.5.1-92 addresses support members; welds; bolted connections; and support anchorage to building structures exposed to an air – indoor uncontrolled environment that will be managed for loss of material due to general and pitting corrosion. For the AMR item that cites generic note E, the LRA credits the Fire Water System Program to manage the aging effect for fire hose reels. The GALL Report recommends using GALL Report AMP XI.S6, "Structures Monitoring," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S6 recommends using periodic visual inspections by qualified personnel, at a frequency not to exceed 5 years, to monitor steel components for loss of material.

The staff's evaluation of the Fire Water System Program is documented in SER Section 3.0.3.1.20. The staff noted that the Fire Water System Program proposes to manage the aging of carbon steel fire hose reels through the use of periodic inspections of hose reels for degradation using acceptance criteria that specify no unacceptable degradation. In its review of components associated with item 3.5.1-92 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Fire Water System Program unacceptable because insufficient information is provided to demonstrate that the program meets the recommendations provided in GALL Report item III.B2.TP-43 with respect to frequency of inspections, qualifications of inspection personnel, and acceptance criteria. By letter dated June 27, 2012, the staff issued RAI 3.5.2.4-4 requesting that the applicant describe how the applicant's Fire Water System Program meets the recommendations in GALL Report item III.B2.TP-43.

In its response dated July 25, 2012, the applicant stated that Element 4 of the Fire Water System AMP includes an enhancement for visual inspection of the hose reels that aligns it with the XI.S6, "Structures Monitoring," for detection of loss of material due to corrosion of steel components. The applicant stated that the acceptance criteria have been revised to verify the presence of no unacceptable degradation, that inspections are performed annually, and qualifications of the personnel performing inspections are consistent with industry guidelines and standards, including the requirements of 10 CFR 50.65.

The staff finds the applicant's response acceptable because the fire hose reels will be inspected by qualified personnel, at an interval more frequent than the 5-year interval recommended by the Structures Monitoring Program, and because the inspections will verify the presence of no unacceptable degradation. The staff's concern described in RAI 3.5.2.4-4 is resolved.

The staff concludes that for LRA item 3.5.1-92, 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).

3.5.2.1.12 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed are not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed are not applicable are not applicable to GGNS.

As discussed in SER Section 3.5.2.1, 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:

- cracks and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations
- reduction of strength and modulus due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to SCC
- loss of material (scaling, spalling) and cracking due to freeze-thaw
- cracking due to expansion and reaction with aggregates
- increase in porosity and permeability due to leaching of calcium hydroxide and carbonation

(2) safety-related and other structures and component supports:

- aging management of inaccessible areas
- reduction of strength and modulus due to elevated temperature
- aging management of inaccessible areas for Group 6 structures
- cracking due to SCC, and loss of material due to pitting and crevice corrosion
- cumulative fatigue damage due to fatigue

(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

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which address several areas:

Cracking and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations. LRA Section 3.5.2.2.1.1, associated with LRA Table 3.5.1, items 3.5.1-1 and 3.5.1-2, addresses concrete components exposed to either a soil or flowing water environment. Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Section XI, Subsection IWL, to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the Structures Monitoring Program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system to control settlement, the GALL Report recommends further evaluation to verify the continued functionality of the dewatering system during the period of extended operation. The GALL Report recommends GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL Program," to manage for cracks and distortion due to increased stress levels from settlement, and GALL Report AMP XI.S6,"Structures Monitoring," to manage for a reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations. For plants that rely on a dewatering system to lower the site groundwater level and control settlement in CLB, the GALL Report recommends further evaluation to verify the continued functionality of the dewatering system during the period of extended operation.

The applicant stated that these items: cracking and distortion due to increased stress levels from settlement are managed by the Containment Inservice Inspection – IWL Program; GGNS does not employ a dewatering system; GGNS does not have an aggressive groundwater, does not utilize porous concrete subfoundations, and was not identified as a plant susceptible to subfoundation erosion (see IN 97-11); Category I structures, except the diesel generator building which is founded on compacted structural backfill, are founded on the Catahoula Formation consisting of hard-to-very-hard silty-to-sandy clay, clayey silt, and locally indurated or cemented clay, silt, and sand layers; and a settlement monitoring program exists. The staff evaluated the applicant's claim by reviewing UFSAR Section 3.8.5, "Foundations," and LRA Section 3.5 and finds it acceptable because the containment foundations are founded on the Catahoula Formation, GGNS does not employ a dewatering system or use porous concrete subfoundations, and the containment structure is monitored for cracking and distortion by the Containment Inservice Inspection – IWL Program.

Reduction of Strength and Modulus Due to Elevated Temperature. LRA Section 3.5.2.2.1.2 associated with 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 will be managed for reduction of strength and modulus of elasticity due to elevated temperature exposure by the Containment Inservice Inspection – IWL Program and Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.1.2 states that reduction in strength and modulus of concrete could occur for PWR and BWR concrete and steel containments exposed to temperatures in excess of those specified in Subsection CC-3440 of ASME Section III, Division 2, for general areas 66 ˚C (150 ˚F) and local areas 93 ˚C (200 ˚F). The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP if any portion of the concrete containment components exceed specified temperature limits (i.e., general area temperature greater than 66 ˚C [150 ˚F] and local area temperature greater than 93 ˚C [200 ˚F]). The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable because during normal operation areas within containment are maintained below a bulk average temperature of 57 ˚C (135 ˚F), and for areas in the cylinder wall where piping penetrations carry hot fluid (pipe temperature greater than 93 ˚C [200 ˚F]) cooling of the concrete is provided by either cooling fins or water jackets to maintain the concrete temperature adjoining the embedded sleeve at or below 93 ˚C (200 ˚F). The applicant also stated that the containment structure is monitored for cracking or indications of a change in material properties by the Containment Inservice Inspection – IWL Program.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL and Structure Monitoring Programs are documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. In its review of components associated with item 3.5.1-3, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWL and Structure Monitoring Programs are acceptable because the applicant noted that the containment concrete temperatures are below the limits provided in Subsection CC-3440 of ASME Section III, Division 2, for both general and local areas.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.1.2 criteria. For the AMR items associated with LRA Section 3.5.2.2.1.2, 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).

<u>Loss of Material Due to General, Pitting, and Crevice Corrosion</u>.

(1) <u>Steel elements of inaccessible areas for all types of PWR and BWR containments</u>. LRA Section 3.5.2.2.1.3 associated with LRA Table 3.5.1, item 3.5.1-4 addresses inaccessible areas steel elements (drywell shell, drywell head, and drywell shell) exposed to either an air-indoor uncontrolled or concrete environment. The GALL Report recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE Program," and GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J Program," to manage for loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because it applies only to Mark III steel containments, however, the applicant stated that the steel liner plate and areas where the steel liner becomes embedded in the concrete floor will be monitored through inspections in accordance with the Containment Inservice Inspection – IWE and Containment Leak Rate Programs. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.1 and 3.5 and finds it acceptable because the GGNS containment uses a Mark III reinforced concrete containment. The staff also noted that the applicant's AMPs meet the recommendations in GALL Report item II.B3.1.CP-113 and therefore is consistent with inspections performed under GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE Program," and GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J Program," which are identified as the appropriate AMPs in the GALL Report for steel elements in inaccessible areas.

LRA Section 3.5.2.2.1.3 associated with LRA Table 3.5.1, item 3.5.1-5, addresses inaccessible areas steel elements (liner, liner anchors, and integral attachments) exposed to air-indoor uncontrolled environment that will be managed for loss of material due to general, pitting, or crevice corrosion by the Containment Inservice Inspection –

IWE and Containment Leak Rate Programs. The criteria in SRP-LR Section 3.5.2.2.1.3 item 1 state that loss of material due to general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments. The SRP-LR recommends further evaluation if corrosion is indicated by ASME Section XI Subsection IWE examinations. GALL Report item II.B3.2.CP-98 states that for inaccessible areas (embedded steel shell or liner); loss of material due to corrosion is not significant if the following four conditions are satisfied:

(1) Concrete meeting the specifications of ACI 318 or 349 and the guidance of ACI 201.2R was used for the containment concrete in contact with the embedded containment shell or liner

(2) The concrete is monitored to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell or liner

(3) The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements

(4) Borated water spills and water ponding on the containment concrete floor is not common and when detected is cleaned up in a timely manner

The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable because the GGNS reinforced concrete containment interior and exterior surfaces of the liner in inaccessible areas are protected from contact with the atmosphere by complete concrete encasement. The applicant also stated that it is not credible for groundwater to reach this portion of the liner since the base mat concrete at this location is greater than 5-foot-thick and poured in multiple horizontal planes. The applicant further stated that a waterproof membrane and work slab is constructed below this area, interior concrete is monitored for cracks under the Structures Monitoring Program, and areas where the steel liner becomes embedded in the concrete floor are inspected in accordance with the Containment Inservice Inspection – IWE and Containment Leak Rate Programs.

In its review of components associated with item 3.5.1-5 the staff found that conditions two and four above were adequately addressed, however, the LRA did not discuss condition one and three adequately in that it was not specified how guidance contained in ACI 201.2R as specified in GALL Report item II.B3.2.CP-98 was met and whether or not a moisture barrier was located at the junction where the liner becomes embedded in the concrete. By letter dated June 27, 2012, the staff issued RAI 3.5.2.2.1.3-1 requesting that the applicant explain how the containment concrete in contact with the embedded steel liner met the guidance contained in ACI 201.2R as specified in the GALL Report, and if a moisture barrier was employed at the junction where the liner becomes embedded in the concrete.

In its response dated July 25, 2012, the applicant stated that the GGNS concrete structures were designed and constructed in accordance with ACI 318-72, which meets many of the recommendations of ACI 201.2R by providing low permeability concrete using a low water-cement ratio based on minimum slump. ACI 318 provides recommendations for selection of cement, aggregates, air-entraining admixtures, water-cement ratio, and reinforcing bar to attain a workable, consistent concrete mixture to produce a durable concrete structure with required compressive strength (i.e., original construction specification for GGNS containment structure required 5,000 psi concrete compressive strength). ACI 318 also provides requirements for concrete placement and curing to ensure that the required concrete quality, durability, and strength are attained.

The applicant further stated that GGNS does not have a moisture barrier at the junction where the containment liner becomes embedded in the concrete, but the liner plate is stainless steel at the lower containment elevations where it is embedded in concrete.

The staff finds the applicant's response acceptable because the applicant designed the structures, selected the materials, developed the concrete mix designs, and placed and cured the concrete in compliance with ACI 318-71 requirements designed to ensure the required concrete quality, durability, and strength are attained. The staff noted that the original construction specification for GGNS containment structure required 5,000 psi concrete compressive strength, which would indicate that the concrete was dense and of high quality. Therefore, the concrete in contact with the embedded steel liner meets the guidance contained in ACI 201.2R. The staff also finds the applicant's response acceptable that a moisture barrier is not provided at the junction where the containment liner becomes embedded in the concrete because, as noted in UFSAR Section 3.8.1.1.2, the containment base mat liner was fabricated from ASTM A240 Type 304 stainless steel plates. The staff's concern described in RAI 3.5.2.2.1.3-1 is resolved.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWE and Containment Leak Rate Programs is documented in SER Sections 3.0.3.1.12 and 3.0.3.1.14, respectively. The staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWE and Containment Leak Rate Programs is acceptable because the applicant proposes to manage the aging of inaccessible areas of steel elements using the Containment Inservice Inspection – IWE and Containment Leak Rate Program, which are the GALL Report recommended programs, and because the applicant has satisfied the four conditions identified in GALL Report item II.B3.2.CP-98.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.1.3 item 1 criteria. For those AMR items associated with LRA Section 3.5.2.2.1.3, 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) Steel torus shell of Mark I containments. LRA Table 3.5.1, item 3.5.1-6 addresses the steel torus shell of Mark I containments exposed to either an air-indoor uncontrolled or treated water environment. The GALL Report recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE Program," and GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J, Program," to manage for loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because GGNS uses a Mark III reinforced concrete containment that does not contain a steel torus shell. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.1 and 3.5 and finds it acceptable because the GGNS uses a Mark III reinforced concrete containment that does 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 air-indoor uncontrolled environment that will be managed for loss of material due to general, pitting, and crevice corrosion by the Containment Inservice Inspection – IWE Program.

The criteria in SRP-LR Section 3.5.2.2.1.3 item 3 state that loss of material due to general, pitting, or crevice corrosion could occur for 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. The SRP-LR also states that further evaluation is required if plant operating experience has identified significant corrosion and recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE." The applicant addressed the further evaluation criteria of the SRP-LR by stating that GGNS is a reinforced concrete Mark III containment with a steel liner and suppression chamber and does not have a torus ring girder or downcomers. The applicant also stated that although this item is only applicable to Mark I and Mark III steel containments, the steel liner plate, suppression pool interior surface, and areas where the steel liner becomes embedded in the concrete floor will be inspected in accordance with the Containment Inservice Inspection – IWE Program for aging effects such as loss of material.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWE Program is documented in SER Sections 3.0.3.1.12. The staff noted that the Containment Inservice Inspection – IWE Program will be used to manage the loss of material of the GGNS suppression chamber shell interior surface. In its review of components associated with item 3.5.1-7, the staff finds the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWE Program is acceptable because the applicant's AMP is consistent with inspections performed under GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE Program," which is identified as the appropriate AMP in the GALL Report.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.1.3 criteria. For those items associated with LRA Section 3.5.2.2.1.3 item 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).

<u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. LRA Section 3.5.2.2.1.4 associated with LRA Table 3.5.1, item 3.5.1-8, addresses steel prestressing tendons exposed to either an air- indoor uncontrolled or air-outdoor environment. The GALL Report identifies the loss of prestress due to relaxation, shrinkage, creep and elevated temperature as a TLAA. The applicant stated that this item is not applicable because the GGNS concrete containment is not prestressed and therefore does not incorporate steel prestressing tendons so a TLAA is not required. The staff evaluated the applicant's claim by reviewing Chapter 3.8 of the UFSAR and LRA Sections 2.4.1 and 3.5 and finds it acceptable because the GGNS has a Mark III containment, which is a "[r]einforced concrete cylindrical structure (not prestressed) with hemispherical head; steel lined," per UFSAR Table 1.3-4, "Comparison of Containment Design Characteristic."

<u>Cumulative Fatigue Damage</u>. LRA Section 3.5.2.2.1.5 associated with LRA Table 3.5.1, item 3.5.1-9 addresses suppression pool steel shells (including welded joints) and penetrations (including penetration sleeves, DM 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 air-indoor uncontrolled, treated water, or air-outdoor environment that will be managed for cumulative fatigue damage due to cyclic loading by a TLAA only if CLB fatigue analysis exists. The criteria in SRP-LR Section 3.5.2.2.1.5 state that if included in the CLB, fatigue

analyses of suppression pool steel shells (including welded joints) and penetrations (including penetration sleeves, DM welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers are TLAAs as defined in 10 CFR 54.3, and TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.6 of the SRP-LR.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA and is required to be evaluated in accordance with 10 CFR 54.21(c) and is documented in LRA Section 4.6, "Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis."

The staff's evaluation of the applicant's TLAAs is documented in SER Chapter 4. The staff noted that TLAAs of the containment liner plate, metal containments, and containment penetrations are addressed in LRA Sections 4.6.1 and 4.6.2. 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.

<u>Cracking Due to Stress Corrosion Cracking</u>. LRA Section 3.5.2.2.1.6 associated with Table 3.5.1, item 3.5.1-10, addresses stainless steel penetration sleeves and penetration bellows, exposed to air-indoor uncontrolled and will be manage for cracking by Containment Leak Rate, Containment Inservice Inspection – IWE, and Fatigue Monitoring programs.

The criteria in SRP-LR Section 3.5.2.2.1, item 6, states that cracking could occur for stainless steel penetration sleeves and bellows exposed to air-indoor uncontrolled. The SRP-LR also states that cracking due to SCC of stainless steel penetration bellows and DM welds could occur in all types of PWR and BWR containments. The SRP-LR also states that the existing program relies on GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J," to manage this aging effect. The SRP-LR further states that the GALL Report recommends further evaluation of additional appropriate examinations and evaluations implemented to detect these aging effects for stainless steel penetration bellows and DM welds.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that SCC is an aging mechanism that requires the simultaneous action of an aggressive chemical environment, sustained tensile stress, and a susceptible material and elimination of any one of these elements will eliminate susceptibility to SCC. The applicant also stated that stainless steel elements of containment, including dissimilar welds, are not susceptible to SCC, because they are not subject to an aggressive chemical environment. The applicant further stated that a review of plant operating experience did not identify cracking of these components and containment pressure boundary functions have not been identified as a concern. The absence of SCC aging effects is confirmed under the Fatigue Monitoring, Containment Inservice Inspection – IWE and Containment Leak Rate Programs.

The staff evaluations of the applicant's Containment Leak Rate, Containment Inservice Inspection – IWE, and Fatigue Monitoring Programs are documented in SER Sections 3.0.3.1.14, 3.0.3.1.12 and 3.0.3.1.18, respectively. The staff noted that the Containment Inservice Inspection – IWE Program includes augmented surface examinations to detect fine cracks.

In its review of the components associated with LRA Table 3.5.1, item 3.5.1-10, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Leak Rate, Containment Inservice Inspection – IWE and Fatigue Monitoring Programs are adequate because the existing Containment Inservice Inspection – IWE Program includes augmented examinations to detect fine cracks which will adequately manage aging during the period of extended operation, consistent with the GALL Report.

Based on the programs identified, the staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.1, item 6, criteria. For those items associated with LRA Section 3.5.2.2.1.6, item 6, 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 manage so that the intended function will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw. LRA Section 3.5.2.2.1.7 associated with LRA Table 3.5.1, item 3.5.1-11 addresses concrete in inaccessible areas of dome, wall, basemat, ring girders, and buttresses exposed to a freeze-thaw environment that will be managed for loss of material and cracking due to freeze-thaw by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The criteria in SRP-LR Section 3.5.2.2.1.7 state that loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR containments and the GALL Report recommends further evaluation of this aging effect for plants located in moderate to severe weathering conditions. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable because GGNS inaccessible and accessible concrete areas are designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete." Concrete quality was determined by following guidance in Subsection 4.2.5 and Table 4.2.5 in ACI 318; and the concrete meets requirements specified in American Society for Testing and Materials (ASTM) standards for selection, application, and testing of concrete and concrete aggregate. The applicant also stated that the absence of concrete aging effects is confirmed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL and Structures Monitoring Programs is documented in SER Sections 3.0.3.1.13, and 3.0.3.1.40, respectively. The staff noted that the concrete structures were designed in accordance with ACI 318; the concrete structures meet requirements for selection, application, and testing of concrete and aggregate; and loss of material (scaling, spalling) and cracking due to freeze-thaw are managed by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. In its review of components associated with item 3.5.1-11, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWL and Structures Monitoring Programs acceptable because: a review of Section 3.8.1, "Concrete Containment," of the UFSAR, LRA Sections 2.4.1 and 3.5, and plant operating experience noted that the entrained air content is within 2 to 6 percent and no degradation due to freeze-thaw effects has been identified in accessible concrete areas. Concrete structures were designed in accordance with ACI 318, and the concrete structures meet requirements for selection, application, and testing of concrete and aggregate.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.1.7 criteria. For those items associated with LRA Section 3.5.2.2.1.7, 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).

Cracking Due to Expansion and Reaction with Aggregates. LRA Section 3.5.2.2.1.8 associated with LRA Table 3.5.1 item 3.5.1-12 addresses concrete in inaccessible areas (containment, dome, wall, basemat, ring girders, buttresses, and concrete fill-in annulus) exposed to any environment that will be managed for cracking due to expansion from reaction with aggregates by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The criteria in SRP-LR Section 3.5.2.2.1.8 state that cracking due to expansion from reaction with aggregates could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The SRP-LR also states that a plant-specific AMP is not required to manage cracking and expansion due to reaction with aggregate or concrete in inaccessible areas if: (1) as described in NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal," 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 addressed the further evaluation criteria of the SRP-LR by stating that is not applicable because GGNS concrete was designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete," which requires the potential reactivity of aggregates to be tested in accordance with ASTM C289 and ASTM C227. The applicant also stated that the aggregate materials were evaluated in accordance with ASTM C295 and the absence of concrete aging effects is confirmed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL and Structures Monitoring Programs is documented in SER Sections 3.0.3.1.13, and 3.0.3.1.40, respectively. The staff noted that GGNS concrete was designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete," which requires the potential reactivity of aggregates to be tested in accordance with ASTM C289 and ASTM C227; aggregate materials were evaluated in accordance with ASTM C295; and the absence of concrete aging effects is confirmed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs. In its review of components associated with item 3.5.1-12, the staff finds that the applicant has met the further evaluation criteria; however, the staff determined the need for additional information. NRC IN 2011-20, "Concrete Degradation by Alkali-Silica Reaction (ASR)," was issued to inform industry of operating experience related to concrete degradation due to ASR. IN 2011-20 was issued on November 18, 2011, which is after the NRC received the GGNS LRA on November 1, 2011. Therefore, by letter dated August 16, 2012, the staff issued RAI 3.5.1.12-1 requesting the following information:

(a) State whether this operating experience is applicable to GGNS; and, if applicable, provide action(s) and/or program to manage this aging effect during the period of extended operation.

(b) Provide the technical justification as to why the AMR items associated with cracking due to expansion from reaction with late- or slow-expanding aggregates are not applicable, and why this aging effect does not require aging management at GGNS.

(c) If it is determined that a revision is needed to LRA Table 3.5.1, items 3.5.1-12, 3.5.1-43, and 3.5.1-50, as necessary, revise further evaluation Sections 3.5.2.2.1.8, 3.5.2.2.2.1.2, and 3.5.2.2.2.3.2; respectively, provide clarification in the evaluation of these sections.

In its response dated September 13, 2012, the applicant stated:

(a) Grand Gulf Nuclear Station (GGNS) operating experience has not identified cracking due to expansion from reaction with aggregates as an aging effect requiring management for accessible and inaccessible concrete areas of structures. Furthermore, inspections of concrete structures at GGNS which are routinely performed under the Structures Monitoring, RG 1.127 and Containment Inservice Inspection – IWL Programs have shown no evidence of alkali-silica reaction (ASR) on concrete. However, as shown in LRA Table 3.5.1, concrete GGNS structures within the scope of license renewal will continue to be inspected during the period of extended operation (PEO) for any evidence of ASR. If concrete inspection results reveal cracking or any evidence of ASR, the site corrective action program requires evaluation of the condition and determination of appropriate corrective action.

(b) Consistent with NUREG-1801 (the GALL Report) (e.g., item II.A1.CP-67), an aging management program is not required if (1) as described in NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C 295 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. GGNS Class I structures and containment accessible and inaccessible concrete (walls, dome, and basemat ring girder) is designed in accordance with ACI standard ACI 318, (Building Code Requirements for reinforced concrete) and GGNS concrete specification requires that the potential reactivity of aggregates be tested in accordance with ASTM C 289 and ASTM C 227. Also ASTM C 295 was used to identify elements in the aggregate, such as aggregates containing strained quartz or microcrystalline quartz, which may be unfavorably reactive with alkalis in cement. Furthermore GGNS concrete structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture resulting in low permeability concrete which reduces the effects of ASR. Cement used in construction of GGNS was Portland Cement Type II, low alkali, conforming to ASTM C 150-72, Standard Specification for Portland Cement. The sum of the tricalcium silicate and tricalcium aluminate did not exceed 55 percent (in accordance with Footnote C, Table 1A on optional Chemical Requirements, ASTM C 150-72). GGNS cement does not contain more than 0.60 percent total alkali equivalent and concrete included pozzolan as an admixture. Furthermore, as discussed in part a. above, inspections of concrete at GGNS have been routinely completed with no evidence of ASR. Therefore cracking, due to expansion from reaction with late- or slow-expanding aggregates, is not an aging effect requiring management for GGNS concrete structures. Nevertheless, ongoing activities of the Structures Monitoring, RG 1.127 and Containment Inservice Inspection IWL programs include inspections that are capable of identifying degradation, if any, attributable to ASR.

(c) A revision to the LRA is not required.

The staff's evaluations of the applicant's Containment Inservice Inspection IWL, Structures Monitoring and RG 1.127 Programs are documented in SER Sections 3.0.3.1.13, 3.0.3.1.40, 3.0.3.1.37, respectively. The staff noted that the concrete structures were constructed from aggregates selected in conformance with specifications and materials conforming to ACI and ASTM standards at the time of construction, water/cement ratios and air entrainment percentages are within limits provided in ACI 318, "Building Code Requirements for Structural Concrete and Commentary" and degradation due to ASR would be identified during inspections performed under the Containment Inservice Inspection – IWL, Structures Monitoring and RG 1.127 Programs. In its review of components associated with LRA items 3.5.1-12, 19, 43, 50, and 54 the staff finds the applicant's proposal to manage aging using the Containment Inservice Inspection – IWL, Structures Monitoring or RG 1.127 programs are acceptable because Section 3.8.1.6.2, "Concrete," of the UFSAR indicates that the aggregate materials complied with ASTM C33, "Standard Specifications for Concrete Aggregates" which notes that the aggregate materials should be evaluated for potential reactivity using ASTM C289, "Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates." For test results that exhibit potentially deleterious character subsequent testing in accordance with ASTM C227, "Standard Test Method for Potential Alkali Reactivity of Cement-Aggregates Combinations" or C1293, "Test Method for Concrete Aggregates by Determination of Length Change of Concrete Due to Alkali-Silica Reaction," to verify the potential for expansion in concrete may be warranted. Furthermore, a review of operating experience has not identified cracking due to expansion from reaction with aggregate materials in accessible concrete structures. The staff's concern described in RAI 3.5.1.12-1 is resolved.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.1.8 criteria. For those items associated with LRA Section 3.5.2.2.1.8, 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).

<u>Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation</u>. 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, buttresses) exposed to water-flowing environment that will be managed for increase in porosity and permeability due to leaching of calcium hydroxide and carbonation by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The criteria in SRP-LR Section 3.5.2.2.1.9 note that increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The SRP-LR also states that a plant-specific AMP is not required to manage increase in porosity and permeability and loss of strength due to 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 functions of the concrete structure. The applicant addressed the further evaluation criteria by stating that this item is not applicable because the concrete was provided with at least the minimum required air content and a low water/cement ratio as specified in ACI 318, "Building Code Requirements for Reinforced Concrete." The applicant also stated that the absence of concrete aging effects has been confirmed by inspections performed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL and Structures Monitoring Programs is documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. The staff noted that operating experience has not identified increases in porosity and permeability due to leaching of calcium hydroxide and carbonation in accessible areas and accessible concrete structures will be inspected for these aging effects. In its review of components associated with items 3.5.1-13 and 3.5.1-14, the staff finds the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWL and Structures Monitoring Programs is acceptable because these AMPs will be used to identify occurrence of porosity and permeability due to leaching of calcium hydroxide and carbonation in accessible areas as a precursor to occurrence of these aging effects in inaccessible areas.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.1.9 criteria. For those items associated with LRA Section 3.5.2.2.1.9, 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 Safety-Related and Other Structures and Component Supports

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2, which address several areas:

<u>Aging Management of Inaccessible Areas.</u>

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 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 that will be managed for loss of material (spalling, scaling) and cracking by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The criteria in SRP-LR Section 3.5.2.2.2.1 item 1 state that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible areas of Groups 1-3, 5, and 7-9 concrete structures exposed to a freeze-thaw environment. The SRP-LR also states that further evaluation is required for plants located in moderate to severe-weathering conditions (weathering index greater than 100 day-inch/yr) as noted in NUREG-1557; however, per the GALL Report, a plant-specific AMP is not required if documented evidence confirms that the existing concrete had an adequate air entrainment content (as per Table CC-2231-2 of ASME Section III Division 2), and subsequent inspections of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable because GGNS inaccessible and accessible concrete areas are designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete;" aggregates were selected in accordance with specifications and materials conforming to ACI and ASTM standards; water/cement ratios and air entrainment percentages are within the limits provided in ACI 318; and the absence of aging effects is confirmed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL and Structures Monitoring Programs is documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. The staff reviewed Section 3.8.1.2, "Applicable Codes, Standards, and Specifications," and Section 3.8.1.6, "Materials, Quality Control, and Special Construction Techniques," of the UFSAR and noted that (1) concrete structures were designed in accordance with ACI 318; and (2) aggregates were selected in accordance with specifications and materials conforming to ACI and ASTM standards. Conformance to ACI 318 ensures that water/cement ratios and air entrainment percentages are within the limits provided by the code and the absence of aging effects is confirmed under the Containment Inservice Inspection – IWL and Structures

Monitoring Programs. In its review of components associated with item 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 Containment Inservice Inspection – IWL and Structures Monitoring Programs acceptable because: a review of UFSAR Section 3.8.1, "Concrete Containment," LRA Sections 2.4.1 and 3.5, and plant operating experience noted that the entrained air content is within 2 to 6 percent and no degradation due to freeze-thaw effects has been identified in accessible concrete areas. Furthermore, concrete structures were designed in accordance with ACI 318, which also provides guidelines for (1) air content for concrete to resist damage from cycles of freezing and thawing; and (2) for selection, application, and testing of concrete and aggregate.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.1 criteria. For those items associated with LRA Section 3.5.2.2.2.1.1, 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) Cracking due to expansion and reaction with aggregates of Groups 1-5 and 7-9 structures.

LRA Section 3.5.2.2.2.1 associated with 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 that will be managed for cracking due to expansion from reaction with aggregates by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The criteria in SRP-LR Section 3.5.2.2.2.1 item 2 state that cracking due to expansion and reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 1-5 and 7-9 structures. The SRP-LR also states that further evaluation is required to determine if a plant-specific AMP is needed to manage cracking and expansion due to reaction with aggregate of concrete in inaccessible areas if the concrete was not constructed in accordance with the recommendations in the GALL Report. The GALL Report states that a plant-specific AMP is not required to manage cracking and expansion due to 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 addressed the further evaluation criteria of the SRP-LR by stating that aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction.

Furthermore, GGNS structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water/cement ratios and air entrainment percentages were within the limits provided in ACI 318, "Building Code Requirements for Reinforced Concrete," which requires that the potential for aggregate reactivity be tested in accordance with ASTM C289, "Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method)," and ASTM C227, "Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method)." Moreover the aggregate materials were evaluated in accordance with ASTM C295, "Standard Guide for Petrographic Examination of Aggregates for Concrete." Therefore, cracking due to expansion and reaction with aggregates for Groups 1–5, 7–9 structures is not an aging effect requiring management.

The absence of concrete aging effects is confirmed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs.

The staff's evaluations of the applicant's Containment Inservice Inspection – IWL and Structures Monitoring Programs are documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. The staff noted that the concrete structures were constructed from aggregates selected in conformance with specifications and materials conforming to ACI and ASTM standards at the time of construction, water/cement ratios and air entrainment percentages are within limits provided in ACI 318, and degradation due to ASR would be identified during inspections performed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs. In its review of components associated with item 3.5.1-43, the staff finds that the applicant has met the further evaluation criteria, however, the staff determined the need for additional information. NRC IN 2011-20 "Concrete Degradation by Alkali-Silica Reaction (ASR)" was issued to inform industry of operating experience related to concrete degradation due to ASR. IN 2011-20 was issued on November 18, 2011, which is after the NRC received the GGNS license renewal application (LRA) on November 1, 2011. Therefore, by letter dated August 15, 2012, the staff issued RAI 3.5.1.12-1 requesting additional information for cracking due to expansion from reaction with aggregates as a possible aging effect for the components listed in item 3.5.1-43. The staff's review of the applicant's response to RAI 3.5.1.12-1, and justification for acceptance is provided in SER Section 3.5.2.2.1.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.1 criteria. For those items associated with LRA Section 3.5.2.2.2.1.2, 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) Cracking and distortion due to increased stress levels from settlement for below-grade inaccessible concrete areas of structures for all groups and reduction in foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundations in below grade inaccessible concrete areas for Groups 1-3, and 5-9 structures.

LRA Section 3.5.2.2.2.1 associated with LRA Table 3.5.1, (1) item 3 5.1-44 addresses concrete for all Groups of structures exposed to increased stress levels due to differential settlement in soil that will be managed for cracking and distortion, and (2) items 3.5.1-45, and 3.5.1-46 address concrete/porous concrete foundations and subfoundations exposed to increased stress levels due to differential settlement as a result of water-flowing under the foundations that will be managed for reduction in foundation strength, cracking due to the differential settlement, erosion of porous concrete subfoundation. Aging effects for these items will be managed by the Containment Inservice Inspection – IWL (for item 3.5.1-45) and Structures Monitoring (for items 3.5.1-44, 3.5.1-45, and 3.5.1-46) programs. The criteria in the SRP-LR 3.5.2.2.2.1 item state that cracking and distortion due to increased stress levels from settlement could occur in below-grade inaccessible concrete areas of structures for all Groups, and reduction in foundation strength and cracking due to differential settlement and erosion of porous concrete sub-foundations could occur in below-grade inaccessible concrete areas of Groups 1-3, 5-9 structures. The SRP-LR also recommends no further evaluation if this activity is included in the scope of the applicant's structures monitoring program, and recommends verification of the continued functionality of the dewatering system to lower the site groundwater level during the period of extended operation if the plant's CLB credits a dewatering program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item does not require management or it is not applicable because with the exception of the diesel generator building, which is founded on compacted structural backfill, the station's foundations, subfoundations, and inaccessible below-grade structures are founded on the Catahoula Formation of Miocene origin, consisting primarily of hard-to-very-hard silty-to-sandy clay, clayey silt, and locally indurated or cemented clay, silt, and sand layers. The applicant also stated that the total settlement is elastic, expected to be less than 1 inch and primarily occurred when the load was applied during construction. Subsequent to construction, onsite monitoring of Category I structures has been shown to be negligible. The applicant further stated that GGNS containment was not identified in IN 97-11 as a plant susceptible to erosion of porous concrete subfoundations and that its groundwater is not aggressive or its chemistry and groundwater conditions have significantly changed. Moreover, any potential total and differential settlements is addressed in the design of foundations at the site. A settlement monitoring program was established to monitor settlements of Category I structures during plant construction and thereafter. Therefore, cracks and distortion due to increased stress levels from settlement for below-grade inaccessible concrete areas of structures for all groups and reduction in foundation strength, and cracking, due to differential settlement and erosion of porous concrete subfoundation in below-grade inaccessible concrete areas for Groups 1–3, 5–9 structures is not an aging effect requiring management for GGNS concrete. Nonetheless, accessible concrete components will be monitored by the Structures Monitoring Program or the Containment Inservice Inspection – IWL Program to confirm the absence of aging effects for cracking and distortion.

The staff's evaluation of the applicant's Inservice Inspection – IWL and Structures Monitoring Programs are documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. The staff noted that the applicant will manage aging of inaccessible concrete areas of structures due to increased stress levels from settlement using the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The staff reviewed the UFSAR and noted that there was not a discussion for either porous foundations or for an active dewatering system and concluded that the applicant does not employ either a dewatering system or have porous concrete subfoundations. The staff also confirmed in UFSAR Section 2.5.4.13.1, "Foundation Rebound and Settlement," that for the containment structure the predicted settlements based on the elastic properties of the Catahoula Formation were about 0.1 inch. Furthermore, differential settlements between adjacent buildings were less than 0.5 inch. For the diesel generator building, the predicted and observed settlements were 0.8 and 0.2 inch respectively. Finally, the staff reviewed UFSAR Figure 2.5, "Instrumentation Location Plan," and confirmed the existence of differential settlement monitoring stations at the containment, auxiliary, turbine and diesel buildings. In its review of components associated with items 3.5.1-44, 3.5.1-45, and 3.5.1-46, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWL and Structures Monitoring Programs is acceptable because a search of applicable UFSAR sections and LRA Sections 2.4 and 3.5 indicate that GGNS does not employ porous concrete subfoundations or rely on a dewatering system to lower the site groundwater table to control settlement, and that in the event of potential differential settlement, monitoring stations exist to monitor potential settlements, if any.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.1 criteria. For those items associated with LRA Section 3.5.2.2.2.1.3, the staff concludes that the LRA is consistent with the GALL Report and that the application 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).

(4) Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation for Groups 1-5 and 7-9 structures.

LRA Section 3.5.2.2.2.1 associated with LRA Table 3.5.1, item 3.5.1-47 addresses concrete in inaccessible areas (exterior above- and below-grade locations and foundations) for Groups 1-5 and 7-9 structures exposed to water flowing that will be managed for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation by the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The criteria in SRP-LR 3.5.2.2.2.1 item 4 states that increases in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible areas of Groups 1-5 and 7-9 structures. The SRP-LR also states that further evaluation is recommended if leaching is observed in accessible areas that impact intended functions to determine if a plant-specific AMP is needed to manage increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation. However, the GALL Report 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, or (2) evaluation determines that the observed leaching of calcium hydroxide and carbonation in accessible areas has no effect on the intended function of the concrete structure. The applicant addressed the further evaluation criteria by stating that this item is not applicable because the concrete was provided with at least the minimum required air content and a low water/cement ratio as specified in ACI 318, “Building Code Requirements for Reinforced Concrete.” Furthermore, aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction to ensure concrete durability. The applicant also stated that GGNS structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Groups 1–5 and 7–9 concrete structures at GGNS use a dense low permeable concrete with an acceptable water-to-cement ratio, which provides an acceptable degree of protection against aggressive chemical attack. The applicant further stated that the water chemical analysis results have confirmed that the site groundwater is considered to be non-aggressive. Therefore, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation of below-grade inaccessible concrete areas are not AERM and the absence of concrete aging effects has been confirmed by inspections performed under the Containment Inservice Inspection – IWL and Structures Monitoring Programs.

The staff’s evaluation of the applicant’s Inservice Inspection – IWL and Structures Monitoring Programs is documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. The staff reviewed USFAR Section 2.4.13.1.3.3, “Chemical Quality of Water,” and verified that groundwater samples obtained from test and observation wells on site and from selected private wells, as well as surface water samples taken from the Mississippi River and Bayou Pierre confirmed that the groundwater is not aggressive. The results of chemical analyses of water samples are presented in UFSAR Table 2.4-21 and indicate that pH, chlorides, and sulfates are below the aggressive environment limits of pH less than 5.5, chlorides in excess of 500 ppm, or sulfates in excess of 1,500 ppm. The staff noted that the applicant will manage increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation using the Containment Inservice Inspection – IWL and Structures Monitoring Programs. The staff also noted that a review of plant operating experience did not identify incidences of leaching or carbonation in accessible concrete areas that affected intended functions. In its review of components associated with item 3.5.1-47, the staff finds the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Containment Inservice Inspection – IWL and Structures Monitoring Programs is acceptable, because (1) these AMPs will be used to identify the occurrence of porosity and permeability due to leaching of calcium hydroxide and carbonation, if any, in accessible areas as a precursor to occurrence of the associated aging effects in inaccessible areas; and (2) plant operating experience thus far has not identified the occurrence of porosity or permeability due to leaching of calcium hydroxide and carbonation in accessible areas.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.1 criteria. For those items that apply to LRA Section 3.5.2.2.2.1.4, 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).

Reduction of Strength and Modulus Due to Elevated Temperature. LRA Section 3.5.2.2.2.2 associated with LRA Table 3.5.1, item 3.5.1-48 addresses Groups 1-5 concrete exposed to elevated temperature environment. The applicant stated that this item is not applicable because during normal operation areas within containment are maintained below a bulk average temperature of 57 °C (135 °F), and for areas in the cylinder wall where piping penetrations carry hot fluid (pipe temperature greater than 93 °C [200 °F]) cooling of the concrete is provided by either cooling fins or water jackets to maintain the concrete temperature adjoining the embedded sleeve at or below 93 °C (200 °F). The applicant also stated that for areas outside the containment, the concrete is not exposed to temperatures that exceed the limits associated with aging degradation due to elevated temperature, and piping penetration temperatures are not in excess of 66 °C (150 °F). In its review of components associated with item 3.5.1-48, the staff finds that the applicant has met the further evaluation criteria because the applicant noted that the Group 1-5 concrete temperatures are below the limits provided in Subsection CC-3440 of ASME Section III, Division 2 for both general and local areas.

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). It recommends further evaluation for the structure/aging effect combinations as identified below in accordance with 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 inspection and maintenance procedures.

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw 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 3.5.1-49 addresses below-grade concrete components of Group 6 structures (inaccessible areas) and exterior above- and below-grade foundation and interior slab concrete exposed to air-outdoor environment that will be managed for loss of material (spalling, scaling) and cracking due to freeze-thaw by the Structures Monitoring and Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs.

The criteria in SRP-LR Section 3.5.2.2.2.3 item 1 state that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. The GALL Report recommends further evaluation of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions (index greater than 100 day-inch/yr) as noted in NUREG-1557; however, a plant-specific AMP is not required if documented evidence confirms that the existing concrete had an adequate air entrainment content (as per Table CC-2231-2 of ASME Section III Division 2), and subsequent inspections of accessible areas did not exhibit degradation related to freeze-thaw. Such inspections, per the GALL Report, should be considered as part of the evaluation process and if degradation is witnessed, then a plant-specific AMP is necessary to manage loss of material (spalling, scaling) and cracking due to freeze-thaw of concrete in inaccessible areas.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that these aging effects are not applicable and do not require management because GGNS inaccessible and accessible concrete areas are designed in accordance with American Concrete Institute Specification ACI 318, "Building Code Requirements for Reinforced Concrete"; aggregates were selected in accordance with specifications and materials conforming to ACI and ASTM standards for a dense durable concrete; water/cement ratios and air entrainment percentages are within the limits provided in ACI 318; and the absence of aging effects is confirmed under the Structures Monitoring and Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs. The staff's evaluation of the applicant's Structures Monitoring and Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs are documented in SER Sections 3.0.3.1.40 and 3.0.3.1.37, respectively. The staff reviewed UFSAR Section 2.3.1, "Regional Climatology," and noted that snowfall is not a rare event in Mississippi. In addition, the staff noted that the area experiences ice storms. UFSAR Tables 2.3-11 and Table 2.3-12 summarize the frequencies and duration for ice storms for each month and year. The staff also reviewed ASTM C33, Figure 1, which provides information on the weathering index for the continental United States, and noted that the GGNS is in the moderate weathering region with potential annual freeze thaw cycles. The staff noted that the concrete structures were designed in accordance with ACI 318; the concrete structures meet requirements for selection, application, and testing of concrete and aggregate; and loss of material (scaling, spalling) and cracking due to freeze-thaw are managed by the Structures Monitoring Program that incorporates ACI 349-3, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," which provide guidelines for inspection, and references NUREG/CR-4652, "Concrete Component Aging and Its Significance Relative to Life Extension of Nuclear Power Plants," according to which operating experience indicated that overall very little damage has been reported in safety-related structures as a direct result of cycles of freezing and thawing. This, in accordance with NUREG/CR-4652, has been attributed to prudent materials selection, concrete testing, quality control, and structural design. In addition the staff noted that the applicant also uses Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs to verify potential cracking. In its review of components associated with item 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 Structures Monitoring and the Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs is acceptable because: a review of Section 3.8 of the UFSAR, LRA Sections 2.4.1 and 3.5, and plant operating experience noted that the entrained air content is within 2 to 6 percent and no degradation due to freeze-thaw effects has been identified in accessible concrete areas; concrete structures were designed in accordance with ACI 318; and the concrete structures meet requirements for selection, application, and testing of concrete and aggregate.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.3 criteria. For those items associated with LRA Section 3.5.2.2.2.3.1, 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) Cracking due to expansion and reaction with aggregates 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 3.5.1-50 addresses below-grade concrete components of Group 6 structures (inaccessible areas) and exterior above- and below-grade foundation and interior slab concrete exposed to air-outdoor environment that will be managed for cracking due to expansion from reaction with aggregates by the Structures Monitoring and Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs. The criteria in SRP-LR Section 3.5.2.2.2.3 item 2 state that cracking due to expansion and reaction of aggregates could occur in below-grade inaccessible areas of Group 6 structures. The SRP-LR also states that further evaluation is recommended to determine if a plant-specific AMP is needed to manage cracking and expansion due to reaction with aggregate of concrete in inaccessible areas. The GALL Report states that a plant-specific AMP is not required to manage cracking and expansion due to 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 addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable. Cracking due to expansion from reaction with aggregates is an aging effect that does not require management because GGNS concrete was designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete," which requires the potential reactivity of aggregates to be tested in accordance with ASTM C289 and ASTM C227. Concrete is made from a durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water/cement ratios and air entrainment percentages are within the limits provided in ACI 318 that require the potential for aggregate reactivity to be tested in accordance with ASTM C289 and ASTM C227 and aggregate materials to be evaluated in accordance with ASTM C295. Furthermore, the applicant stated that the GGNS below-grade environment, exhibiting a pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1,500 ppm, is not aggressive. The absence of concrete aging effects is confirmed under the Structures Monitoring and the Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs.

The staff's evaluation of the applicant's Structures Monitoring and Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs is documented in SER Sections 3.0.3.1.40 and 3.0.3.1.37, respectively. The staff reviewed UFSAR Table 2.4-21, "Results of Chemical Analyses of Water Samples," and confirmed that the groundwater (as calcium carbonate in nearby wells) or alluvium alkalinity within 2 miles radius from the plant to be 0, which translates to a pH of 7 or slightly more. Total chlorides and sulfates are well below the 500 and 1,500 ppm marks. The staff also reviewed UFSAR Chapter 3 and confirmed that the applicant has used ACI 318, "American Concrete Institute (ACI), Building Code Requirement for Reinforced Concrete," throughout the plant construction, which requires that the potential for aggregate reactivity be tested in accordance with ASTM C289, "Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method)," and ASTM C227, "Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method)." Moreover the aggregate materials were evaluated in accordance with ASTM C295, "Standard Guide for Petrographic Examination of Aggregates for Concrete" and selected locally. The staff also noted at the time of construction, water/cement ratios and air entrainment percentages are within limits provided in ACI 318, and the absence of concrete aging effects is confirmed under the Structures Monitoring and Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Programs. In its review of components associated with item 3.5.1-50, the staff finds that the applicant has met the further evaluation criteria, however, the staff determined the need for additional information. IN 2011-20 "Concrete Degradation by Alkali-Silica Reaction (ASR)" was issued to inform industry of operating experience related to concrete degradation due to ASR and was issued on November 18, 2011, which is after the NRC received the LRA on November 1, 2011. Therefore, by letter dated August 15, 2012, the staff issued RAI 3.5.1.12-1 requesting additional information for cracking due to expansion from reaction with aggregates as a possible aging effect for the components listed in item 3.5.1-43. The staff's review of the applicant's response to RAI 3.5.1.12-1, and justification for acceptance is provided in SER Section 3.5.2.2.1.

The staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.3 criteria. For those items associated with LRA Section 3.5.2.2.2.3.2, 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) Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation that could occur in below-grade inaccessible concrete areas of Group 6 structures.

LRA Section 3.5.2.2.2.3 associated with LRA Table 3.5.1, item 3.5.1-51 addresses concrete in inaccessible areas of Group 6 concrete structures exposed to water flowing that will be managed for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation by the Structures Monitoring Program. The SRP-LR states that further evaluation is recommended to determine if a plant-specific AMP is needed to manage increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation of concrete in inaccessible areas. The SRP-LR also states that a plant-specific AMP is not required for reinforced concrete structures exposed to flowing water 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 functions of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable as the listed aging effects do not require management because the GGNS below-grade environment is not aggressive and the concrete was provided with at least the minimum required air content and a low water/cement ratio as specified in ACI 318, “Building Code Requirements for Reinforced Concrete.” The applicant also stated that the absence of concrete aging effects in accessible areas has been confirmed by inspections performed under the Structures Monitoring Program (see LRA Section 3.5.2.2.2.1 item 4 associated with LRA Table 3.5.1, item 3.5.1-47).

The staff‘s evaluation of the applicant‘s Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that the GGNS below-grade environment as indicated above in the evaluation of 3.5.2.2.2.3 item (2) associated with LRA Table 3.5.1, item 3.5.1-50 is not aggressive (alkalinity at or near zero, chlorides and sulfates well below the 500 and 1,500 ppm marks) and therefore it could adversely affect below-grade concrete and its constituents. Furthermore, concrete was placed with the minimum required air content and had a water/cement ratio in compliance with ACI 318 requirements. Absence of similar aging effects also have been noted in LRA Section 3.5.2.2.2 associated with LRA Table 3.5.1, item 3.5.1-47, and the Structures Monitoring Program will be used to manage aging of the Group 6 concrete structures for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation. In its review of components associated with item 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 Structures Monitoring Program is acceptable because the below-grade concrete is not exposed to an aggressive environment, has met the minimum required air content, had a water/cement ratio in compliance with ACI 318 requirements, and a review of plant operating experience did not identify any incidences of leaching or carbonation in accessible areas that may affect intended functions.

The staff determines that the applicant’s evaluation meets SRP-LR Section 3.5.2.2.2.3 criteria. For those items that apply to LRA Section 3.5.2.2.2.3.3, 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).

<u>Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion</u>. LRA Section 3.5.2.2.2.4, associated with LRA Table 3.5.1, item 3.5.1-52 addresses cracking and loss of material due to pitting and crevice corrosion of Groups 7 and 8 stainless steel tank liners exposed to water standing. The applicant stated that this item is not applicable because GGNS does not have Group 7 or Group 8 structures with stainless steel liners. 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.

<u>Cumulative Fatigue Damage Due to Fatigue</u>. 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 due to cyclic loading in component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports exposed to air-indoor uncontrolled. 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 applicant’s 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 and, 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 3.5.2-4, 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 3.5.2-4, 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.

For the LRA Table 3.5.2 items that the applicant identified as generic note I, plant specific note 501, the applicant did not provide sufficient information as to why the GGNS environment is not conducive to the listed aging effects. Therefore, by letter dated October 19, 2012, the staff issued RAI 3.5.1-2 requesting that the applicant clarify if the listed aging effects will be managed by the proposed program(s) when the "Discussion" column states that listed aging effect does not require management at GGNS, and if the aging effect will not be managed, to provide technical justification as to why the GGNS environment would not be conducive to the listed aging effects.

In its response dated November 19, 2012, the applicant clarified that for each GGNS LRA Table 3.5.2 item where generic note I and plant-specific note 501 are cited, the listed aging effects will be managed by the identified program(s). In addition, the applicant provided technical justification as to why the environment would not be conducive to the listed aging effects.

The staff finds the applicant's response acceptable because the applicant provided clarification that the listed aging effects will be managed by the identified program(s), which are consistent with the recommendations in the GALL Report.

3.5.2.3.1 Containment Building - Summary of Aging Management Review – LRA Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, which summarizes the results of AMR evaluations for the containment building component groups.

Concrete Elements Exposed to Soil. In LRA Table 3.5.2-1, the applicant stated that for concrete containment foundation exposed to soil, cracking and distortion due to increased stress levels from settlement are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects but that an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Containment Inservice Inspection – IWL Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL program is documented in SER Section 3.0.3.1.13. Although the applicant stated that cracking and distortion due to increased stress levels from settlement are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-1 is consistent with the aging management program identified in the GALL Report and the components are included in the Containment Inservice Inspection – IWL Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these structures and components, as documented in item II.B3.2.CP-105 (SRP-LR Table 3.5-1, item 1).

Concrete Elements Exposed to Air–Indoor Uncontrolled or Air–Outdoor Environments. In LRA Table 3.5.2-1, the applicant stated that for concrete containment base slab/foundation exposed to air-indoor and concrete main steam pipe tunnel exposed to air-outdoor, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Containment Inservice Inspection – IWL and Structures Monitoring Programs, respectively, to confirm the absence of aging effects.

The staff's evaluation of the applicant's Containment Inservice Inspection – IWL and Structures Monitoring Programs are documented in SER Sections 3.0.3.1.13 and 3.0.3.1.40, respectively. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-23 is consistent with the aging management program identified in the GALL Report and the components are included in the Containment Inservice Inspection – IWL and Structures Monitoring Programs to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item II.B3.2.CP-89 (SRP-LR Table 3.5-1, item 23).

Concrete Elements Exposed to Air–Indoor Uncontrolled or Fluid Environments. In LRA Table 3.5.2-1, the applicant stated that for concrete beams, columns, floor slabs, interior walls, drywell wall and floor slab, and reactor pedestal exposed to air-indoor uncontrolled and concrete drywell floor slab exposed to a fluid environment, increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Programs to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that increase in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-24 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these structures and/or components, as documented in item II.B3.2.CP-84 (SRP-LR Table 3.5-1, item 24).

Group 1, Concrete Structures Exposed to Air-Indoor Uncontrolled Environment. In LRA Table 3.5.2-1, the applicant stated that for concrete containment sump structures, and upper containment pool floor and walls exposed to air-indoor uncontrolled, cracking due to expansion from reaction with aggregates is not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff reviewed the associated items in the LRA to confirm that these aging effects are not applicable for this component, material, and environmental combination and determined the need for additional information. By letter dated August 15, 2012, the staff issued RAI 3.5.1.12-1 requesting the technical justification for the non-applicability of cracking due to expansion from reaction with aggregates as a possible aging effect for the components listed in item 3.5.1-54. The staff's review of the applicant's response to RAI 3.5.1.12-1, and justification for acceptance is provided in SER Section 3.5.2.2.1.

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).

3.5.2.3.2 Water Control Structures - Summary of Aging Management Review – LRA Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the water control structures component groups.

Group 6 Concrete Structures Exposed to Air–Indoor Uncontrolled or Air-Outdoor. In LRA Table 3.5.2-2, the applicant stated that for concrete floor slab, interior walls, roof hatches, and roof slabs exposed to air-indoor uncontrolled or air-outdoor, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is documented in SER Section 3.0.3.1.37. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-59 is consistent with the aging management program identified in the GALL Report and the components are included in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item III.A6.TP-38 (SRP-LR Table 3.5-1, item 59).

Group 6 Concrete Structures Exposed to a Fluid Environment. In LRA Table 3.5.2-2, the applicant stated that for concrete beams, columns, floor slab, foundation, and interior walls exposed to a fluid environment, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is documented in SER Section 3.0.3.1.37. Although the applicant stated that increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-61 is consistent with the aging management program identified in the GALL Report and the components are included in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item III.A6.TP-37 (SRP-LR Table 3.5-1, item 61).

Groups 6 Concrete Structures Exposed to Soil. In LRA Table 3.5.2-2, the applicant stated that for concrete foundation exposed to soil, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-65 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item III.A6.TP-104 (SRP-LR Table 3.5-1, item 65).

<u>Galvanized Steel Exposed to Fluid Environment</u>. In LRA Table 3.5.2-2, the applicant stated that the galvanized steel structural beams, columns, and plates exposed to a fluid environment will be managed for loss of material by the Structures Monitoring Program. The AMR item cites generic note J.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all the credible aging effects for this component, material, and environment description. The staff noted in GALL Report Section IX.C, "Selected Definitions and Use of Terms for Describing and Standardizing Materials," that galvanized steel in the presence of moisture should be classified under the category "steel." Based on its review of the GALL Report and M.G. Fontana, "*Corrosion Engineering*," Third Edition, McGraw-Hill, 1986, which states galvanized steel in an outdoor environment (where it would be exposed to moisture) has no AERM as a result of the corrosion protection provided by the zinc coating that is enhanced by the buildup of corrosion products deposited out of solution, 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 applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program, with enhancements, acceptable because the galvanized steel structural, beams, columns, and plates exposed to a fluid environment will be inspected at intervals not to exceed 5 years and evaluated using acceptance criteria based on industry codes, standards, and guidelines, including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R, and the book "*Corrosion Engineering*" indicates that the zinc coating will provide corrosion protection in a moist environment.

<u>Fiber Reinforced Polyester Exposed to Fluid Environment</u>. In LRA Table 3.5.2-2, the applicant stated that fiber reinforced polyester cooling tower drift eliminators will be managed for cracking by the Structures Monitoring Program. The AMR cites generic note J.

The staff reviewed the associated items in the LRA and considered whether the aging effects the applicant proposed constitute all the credible aging effects for this component, material, and environment description. The staff noted that fiberglass is a composite material comprised of glass fibers and a polyester or epoxy resin. Fiberglass composites have excellent moisture resistance and chemical resistance to many corrosive materials, including acids (specifically including boric acid), chlorides, nitrates, and sulfates, and that the maximum recommended operating temperature for fiberglass is 200˚F. The staff also noted that the fiber reinforced cooling tower drift eliminators will not be exposed to temperatures above ambient, and cracking resulting from exposure to fluid environment will be managed by the Structures Monitoring Program.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the fiber-reinforced polyester cooling tower drift eliminators exposed to a fluid environment will be inspected at intervals not to exceed 5 years in accordance with guidelines in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R, and operating experience indicates that the fiber-reinforced polyester materials have good chemical and moisture resistance.

Ceramic Tile Cooling Tower Fill Exposed to Fluid Environment. In LRA Table 3.5.2-2, the applicant stated that ceramic tile cooling tower fill exposed to fluid environment has no AERMs, but will be managed for cracking by the Structures Monitoring Program. The AMR cites generic note J.

The staff reviewed the associated items in the LRA and considered whether the aging effects the applicant proposed constitute all the credible aging effects for this component, material, and environment description. The staff noted ceramic tiles are a mixture of clays and other natural materials that are mined from the earth, shaped, and fired at high temperature, and thus provide a durable material with closed surface pore structure that is resistant to water absorption. The staff also noted that the durability of ceramic tiles has been demonstrated through their use for many years as roof tiles, and although no AERMs were identified for the ceramic tile cooling tower fill, the applicant will use the Structures Monitoring Program as an AMP.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff noted that under the Structures Monitoring Program, after enhancement, these components will be inspected at intervals not to exceed 5 years, and evaluated using acceptance criteria based on industry codes, standards, and guidelines including NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the ceramic tile cooling tower fill exposed to a fluid environment will be inspected at intervals not to exceed 5 years in accordance with guidelines in NEI 96-03, ANSI/ASCE 11-99, and ACI 349.3R, and a review of operating experience indicates that the ceramic tile materials have good chemical and moisture resistance.

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 Turbine Building, Process Facilities, and Yard Structures - Summary of Aging Management Review – LRA Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the turbine building, process facilities, and yard structures component groups.

Concrete Fire Barriers Exposed to Uncontrolled Indoor Air. In LRA Tables 3.5.2-3 and 3.5.2-4, the applicant stated that for concrete walls, beams, columns, floor slabs, roof slabs, manways, hatches, manhole covers, hatch covers, and floor curbs exposed to uncontrolled indoor air, concrete cracking and spalling are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Fire Protection and Structures Monitoring Programs to confirm the absence of aging effects.

The staff reviewed the associated items in the LRA to confirm that these aging effects are not applicable for this component, material, and environmental combination. Based on its review of the GALL Report, item VII.G.A-90, the staff noted that cracking and spalling are applicable aging effects for concrete fire barriers exposed to indoor air. However, since the applicant will inspect these components for aging effects using the Fire Protection and Structures Monitoring Program, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item VII.G.A-90 (SRP-LR Table 3.3-1, item 60).

Concrete Fire Barriers Exposed to Outdoor Air. In LRA Tables 3.5.2-3 and 3.5.2-4, the applicant stated that for concrete walls, roof slabs, manways, hatches, manhole covers, and hatch covers exposed to outdoor air, concrete cracking and loss of material are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Fire Protection and Structures Monitoring Programs to confirm the absence of aging effects.

The staff reviewed the associated items in the LRA to confirm that these aging effects are not applicable for this component, material, and environmental combination. Based on its review of the GALL Report, item VII.G.A-92, the staff noted that cracking and loss of material are applicable aging effects for concrete fire barriers exposed to outdoor air. However, since the applicant will inspect these components for aging effects using the Fire Protection and Structures Monitoring Programs, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item VII.G.A-92 (SRP-LR Table 3.3-1, item 61).

Inaccessible Areas, Group 3 Concrete Structures Exposed to Air-Outdoor Environment. In LRA Table 3.5.2-3, the applicant stated that for concrete CST/RWST retaining basin (wall) and diesel fuel tank access tunnel slab exposed to air-outdoor, cracking due to expansion from reaction with aggregates are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff reviewed the associated items in the LRA to confirm that these aging effects are not applicable for this component, material, and environmental combination and determined the need for additional information. By letter dated August 15, 2012, the staff issued RAI 3.5.1.12-1 requesting the technical justification for the non-applicability of cracking due to expansion from reaction with aggregates as a possible aging effect for the components listed in item 3.5.1-54. The staff's review of the applicant's response to RAI 3.5.1.12-1, and justification for acceptance is provided in SER Section 3.5.2.2.1.

Concrete Structures Exposed to Soil. In LRA Table 3.5.2-3, the applicant stated that for concrete sumps exposed to soil, cracking, and distortion due to increased stress levels from settlement are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that cracking and distortion due to increased stress levels from settlement are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-44 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item III.A7.TP-30 (SRP-LR Table 3.5-1, item 44).

Groups 1, 3, and 5, Concrete Structures Exposed to Soil. In LRA Table 3.5.2-3, the applicant stated that for concrete CST/RWST retaining basin (wall), duct banks, exterior walls (below-grade), foundations (buildings, transformers, tanks, circuit breakers), and manholes exposed to soil, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-65 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in items III.A1.TP-27, III.A3.TP-27, and III.A5.TP-27, (SRP-LR Table 3.5-1, item 65).

Groups 1-5, 7, and 9 Concrete Structures Exposed to Air-Indoor Uncontrolled or Air-Outdoor. In LRA Table 3.5.2-3, the applicant stated that for concrete roof slabs exposed to air-indoor uncontrolled or air-outdoor, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-66 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in items III.A1.TP-26, III.A3.TP-26, and III.A5.TP-26 (SRP-LR Table 3.5-1, item 66).

Groups 1-5, and 7-9 Concrete Structures Exposed to Air-Indoor Uncontrolled. In LRA Table 3.5.2-3, the applicant stated that for concrete sumps exposed to air-indoor uncontrolled, increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-67 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in item III.A7.TP-28 (SRP-LR Table 3.5-1, item 67).

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 Bulk Commodities - Summary of Aging Management Review – LRA Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for the bulk commodities component groups.

Carbon Steel Fire Doors Exposed to Air-Outdoor. In LRA Table 3.5.2-4, the applicant stated that carbon steel fire doors exposed to air-outdoor will be managed for loss of material by the Fire Protection Program. The AMR item cites generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, item VII.G.A-22, which states that steel fire doors exposed to outdoor air are susceptible to loss of material due to wear and recommends GALL Report AMP XI.M26, "Fire Protection," to manage the aging effect. However the applicant stated in LRA Table 3.3.1, item 3.3.1-59, that loss of material due to wear is not an applicable aging effect for fire doors because wear is an event driven effect. Instead, the applicant will manage fire doors for other types of loss of material. The staff finds the applicant's proposal to manage loss of material due to mechanisms other than wear acceptable because the inspection methods used to detect loss of material due to other aging mechanisms are the same as those used to detect wear.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.1.19. The staff finds the applicant's proposal to manage aging using the Fire Protection Program acceptable because the program includes visual inspections and functional tests of fire doors that are capable of identifying loss of material, regardless of mechanism, to ensure the fire door's operability is maintained.

Concrete Fire Barriers Exposed to Air-Indoor Uncontrolled or Air-Outdoor. The staff's evaluation for concrete fire barriers exposed to uncontrolled indoor and outdoor air, which will be managed for aging using the Fire Protection and Structures Monitoring Programs and cite generic note I, is documented in SER Section 3.5.2.3.3.

Aluminum Vents and Louvers Exposed to Air-Outdoor. In LRA Table 3.5.2-4, the applicant stated that for aluminum vents and louvers exposed to air-outdoor, no AERM or AMP is proposed. The AMR item cites generic note I. The AMR item also cites plant-specific note 503 that states, "[v]apors of sulfur dioxide or other similar substances do not chemically pollute the ambient outdoor environment and the external environment does not contain saltwater or high chloride content; therefore aging management is not required for aluminum and stainless steel components exposed to the external environment."

The staff reviewed the associated LRA items to confirm that this aging effect is not applicable for this component, material, and environmental combination. The SRP-LR states, in Table 3.4.1, item 35, that aluminum components exposed to outdoor air are susceptible to loss of material due to pitting and crevice corrosion. By letter dated June 20, 2012, the staff issued RAI 3.5.2.3.4-3, requesting that the applicant explain why loss of material due to pitting and crevice corrosion is not an applicable aging effect for aluminum components exposed to outdoor air.

In its response dated July 19, 2012, the applicant stated, "[t]he aluminum vents and louvers in an air-outdoor environment will be treated as susceptible to an aging effect of loss of material." LRA Table 3.5.2-4 was amended to state that the aluminum vents and louvers exposed to an outdoor air environment will be managed for loss of material by the Structures Monitoring Program. The amended item cites LRA Table 3.5.1, item 3.5.1-93 and generic note A, and plant-specific note 503 was deleted.

The staff noted that item 3.5.1-93, GALL Report item TP-6, states that galvanized steel, aluminum, and stainless steel support members, welds, bolted connections, and support anchorages to building structure exposed to outdoor air may be managed for loss of material due to pitting and crevice corrosion by GALL Report AMP XI.S6, "Structures Monitoring," program. The staff noted that generic note A was not appropriately cited given that vents and louvers are not support members, welds, bolted connections, or support anchorages to building structures. Nevertheless, the staff does agree that the vents and louvers are closely aligned to structural members based on a review of LRA Sections 2.3.3.18, 2.4.2, 2.4.3, and Table 2.4-4, because the vents and louvers are associated with building structures.

The staff finds the applicant's response and its proposal to manage aging for aluminum vents and louvers exposed to outdoor air using the Structures Monitoring Program acceptable because the LRA has been amended to manage loss of material for aluminum vents and louvers and the Structures Monitoring Program includes visual inspections that are capable of detecting pitting and crevice corrosion. The staff's concern described in RAI 3.5.2.3.4-3 is resolved.

Non-Metallic Fire Barriers Exposed to Uncontrolled Indoor Air. In LRA Table 3.5.2-4, the applicant stated that cerafiber, cerablanket, Thermo-lag, and 3M Interam fire wraps exposed to uncontrolled indoor air will be managed for loss of material and cerafiber and elastomer fire stops exposed to air-indoor uncontrolled will be managed for cracking, delamination, and separation by the Fire Protection Program. The AMR items cite generic note J.

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. Although the GALL Report does not have any AMR items for non-metallic fire barriers, the staff noted that GALL Report AMP XI.M26, "Fire Protection," does include fire resistant materials, including fire wrapping, within the scope of the AMP. GALL Report AMP XI.M26 recommends that these materials be managed for cracking, and loss of material and seal separation. Based on its review of the GALL Report, the staff finds that the applicant has identified the credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.1.19. The staff finds the applicant's proposal to manage aging using the Fire Protection Program acceptable because the program includes visual inspections of fire barriers of various material types that are capable of detecting degradation of the fire barrier prior to loss of intended function.

Pyrocrete Fire Proofing Exposed to Air-Indoor Uncontrolled. In LRA Table 3.5.2-4, the applicant stated that pyrocrete fire proofing exposed to air-indoor uncontrolled will be managed for no aging effects by the Fire Protection and Structures Monitoring Programs. The AMR items cite generic note J. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation.

Although the GALL Report does not have any AMR items for non-metallic fire barriers, the staff noted that GALL Report AMP XI.M26, "Fire Protection," does include fire resistant materials, including spray-on fireproofing, within the scope of the AMP. The staff noted that pyrocrete is a cementitious spray-on fire proofing material. GALL Report AMP XI.M26 recommends that concrete materials be managed for cracking, spalling, and loss of material. The staff noted that pyrocrete has applicable aging effects when exposed to indoor air. However, the staff finds the applicant's proposal acceptable because the applicant will inspect these components to confirm the absence of aging effects using programs that inspect for the GALL Report identified aging effects of cracking, spalling, and loss of material.

The staff's evaluation of the applicant's Fire Protection and Structures Monitoring Programs are documented in SER Sections 3.0.3.1.19 and 3.0.3.1.40. The staff finds the applicant's proposal to manage aging using the Fire Protection and Structures Monitoring Programs acceptable because the programs include visual inspections of fire barriers of various material types that are capable of detecting cracking, spalling, and loss of material prior to loss of intended function.

Stainless Steel Supports, Base Plates, and Bolting Exposed to Air-Outdoor. In LRA Table 3.5.2-4, the applicant stated that for stainless steel base plates, anchor bolts, structural bolting, ASME Class 1, 2, 3, and MC support bolting, and component and piping supports exposed to air-outdoor, there are no aging effects and no AMP is proposed. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that sulfur dioxide vapors or other similar substances do not chemically pollute the ambient outdoor environment at GGNS and the external environment does not contain saltwater or high chloride content; therefore, aging management is not required for aluminum and stainless steel components exposed to the external environment.

The staff reviewed the associated items in the LRA and considered whether the aging effects the applicant proposed constitute all of the credible aging effects for this component, material, and environment description. The GALL Report states that stainless steel components exposed to outdoor air can be susceptible to cracking and loss of material depending on the outdoor environmental conditions. SRP-LR Sections 3.4.2.2.2 and 3.4.2.2.3 state that cracking and loss of material are applicable in outdoor environments high in chlorides, such as those near a saltwater coastline, near a highway treated with salt, with chlorides in the soil, or that have a cooling tower treated with chlorine. LRA Section 3.4.2.2.2 states that the applicant has a cooling tower treated with hypochlorite. By letter dated May 24, 2012, the staff issued RAI 3.5.2.4-1 requesting that the applicant explain why cracking and loss of material are not applicable aging effects for stainless steel components exposed to outdoor air given that the outdoor air environment contains cooling tower vapor that contains chlorides.

In its response dated June 22, 2012, the applicant stated that stainless steel structural components exposed to outdoor air are susceptible to cracking and loss of material. The applicant revised the LRA to credit the Structures Monitoring Program to manage cracking and loss of material for the stainless steel base plates, anchor bolts, structural bolting, and component and piping supports exposed to air-outdoor, citing generic note G. The applicant also revised the LRA to credit the ASME Section XI, Subsection IWF, program to manage cracking and loss of material for ASME Class 1, 2, 3, and MC supports bolting, citing generic note G. The staff's review of the applicant's Structures Monitoring and ISI – IWF Programs are documented in SER Section 3.0.3.1.40 and 3.0.3.1.23, respectively. The staff noted that GALL Report item III.B2.TP-6 recommends that stainless steel support members, bolted connections, and support anchorage exposed to outdoor air be managed for loss of material using GALL Report AMP XI.S6, "Structures Monitoring." GALL Report AMP XI.S6 recommends performing visual inspections to manage loss of material. The staff also noted that GALL Report item V.B.EP-103 recommends that stainless steel components exposed to outdoor air be managed for cracking using GALL Report AMP XI.36, "External Surfaces Monitoring of Mechanical Components," which uses visual inspections to manage cracking for this component group. The staff finds the applicant's response and its proposal to manage cracking and loss of material for these components using the Structures Monitoring and ISI – IWF Programs acceptable because the programs include visual inspections that are capable of detecting cracking and loss of material, and are consistent with the inspection methods recommended by the GALL Report to manage aging for this component group. The staff's concern described in RAI 3.5.2.4-1 is resolved.

<u>Structural Bolting Exposed to Air-Outdoor</u>. In LRA Table 3.5.2-4, the applicant stated that stainless steel base plates, component and piping supports, anchor bolts, and structural bolting exposed to air-outdoor will be managed for cracking and loss of material by the Structures Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects the applicant proposed constitute all of the credible aging effects for this component, material, and environment description. Based on its review of GALL Report items III.B2.TP-6 and III.B4.TP-6, which states that support members; welds; bolted connections; and support anchorage to building structures exposed to air-outdoor are susceptible 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 applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. The staff finds the applicant's proposal to manage aging using the

Structures Monitoring Program acceptable because these components are within the scope of the Structures Monitoring Program and the inspections will be done by qualified personnel consistent with the recommendations in GALL Report AMP XI.S6.

Groups 1-5 and 7-9 Concrete Structures Exposed to Air-Indoor Uncontrolled or Air-Outdoor. In LRA Table 3.5.2-4, the applicant stated that for concrete equipment pads/foundations, flood curbs, manways, hatches, manhole covers, hatch covers, and support pedestals exposed to air-indoor uncontrolled or air-outdoor, cracking due to expansion from reaction with aggregates is not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff reviewed the associated items in the LRA to confirm that these aging effects are not applicable for this component, material, and environmental combination and determined the need for additional information. By letter dated August 15, 2012, the staff issued RAI 3.5.1.12-1 requesting the technical justification for the non-applicability of cracking due to expansion from reaction with aggregates as a possible aging effect for the components listed in item 3.5.1-54. The staff's review of the applicant's response to RAI 3.5.1.12-1, and justification for acceptance is provided in SER Section 3.5.2.2.1.

Group 6 Concrete Structures Exposed to Air-Indoor Uncontrolled or Air-Outdoor. In LRA Table 3.5.2-4, the applicant stated that for concrete equipment pads/foundations exposed to air-indoor uncontrolled or air-outdoor, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is documented in SER Section 3.0.3.1.37. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-59 is consistent with the aging management program identified in the GALL Report and the components are included in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in items III.A6.TP-38 (SRP-LR Table 3.5-1, item 59).

Groups 1-5, 7, and 9 Concrete Structures Exposed to Air-Indoor Uncontrolled or Air-Outdoor. In LRA Table 3.5.2-4, the applicant stated that for concrete manways, hatches, manhole covers, and missile shields exposed to air-indoor uncontrolled or air-outdoor, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable. The AMR items cite generic note I. The AMR items also cite a plant-specific note that states that the given environment is not conducive to the stated aging effects, but an AMP will be used to confirm the absence of aging effects during the period of extended operation. The applicant credited the Structures Monitoring Program to confirm the absence of aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.1.40. Although the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable because the environment is not conducive to these aging effects, in response to RAI 3.5.1-2, the applicant clarified that item 3.5.1-66 is consistent with the aging management program identified in the GALL Report and the components are included in the Structures Monitoring Program to confirm the absence of these aging effects. Therefore, the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report recommendations for managing aging for these components, as documented in items III.A3.TP-26 and III.A7.TP-26 (SRP-LR Table 3.5-1, item 66).

<u>Fiberglass/Calcium Silicate Insulation Exposed to Air-Indoor Uncontrolled</u>. In LRA Table 3.5.2-4, the applicant stated that for fiberglass/calcium silicate insulation exposed to air-indoor uncontrolled environment aging effects are not applicable and no AMP is proposed. The applicant cites generic note J and plant-specific note 501. Plant-specific note 501 states that the GGNS environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.

The staff reviewed the associated items in the LRA to confirm that there are no aging effects applicable for this component, material, and environment combination. The staff noted that the thermal resistance (insulating) characteristics of mass insulation systems are not expected to naturally degrade over the course of their service life as proper selection, design, and installation for the specific service and condition is assumed. The staff also noted that unless protective coverings of mass insulation systems are damaged, loss/degradation of insulating material is not a concern and mass insulation systems used in nuclear plant applications typically are sealed and include a combination of insulating material and a weather barrier, vapor barrier, condensate barrier, or covering for the specific service; and this outer covering (or barrier) protects mass insulation from the weather, solar/UV radiation, or atmospheric contaminants, and mechanical damage, but permits the evaporation of any moisture vapor. The staff finds the applicant's proposal acceptable because these materials perform well when exposed to air and are properly jacketed to prevent moisture intrusion.

<u>Rubber Water Stops Exposed to Air-Indoor Uncontrolled</u>. In LRA Table 3.5.2-4, the applicant stated that for rubber water stops exposed to air-indoor uncontrolled environment aging effects are not applicable and no AMP is proposed. The applicant cites generic note J.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all the credible aging effects for this component, material, and environment description. The staff noted that in GALL Report Section IX.F, "Selected Definitions and Use of Terms for Describing and Standardizing Aging Mechanisms," it identifies elastomer (i.e., rubber) degradation mechanisms as cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and weathering. The GALL Report also notes that for rubber materials hardening and loss of strength of elastomers can be induced by elevated temperature (over about 95 °F [35 °C]), and additional aging factors such as exposure to ozone, oxidation, and radiation. Since the rubber water stops provide a flood barrier function and loss of sealing can result from a number of degradation mechanisms, the staff is uncertain why no AERMs have been identified for the rubber water stops exposed to air-indoor uncontrolled environment and an AMP has not been identified (e.g., GALL Report item VII.F1.AP-102 notes elastomers in an air uncontrolled environment are subject to hardening and loss of strength due to degradation and identifies an AMP, and SRP-LR Table 3.5-1 item 72 identified loss of sealing due to deterioration of seals, gaskets, and moisture barriers [caulking, flashing, and other sealants] as an aging effect/mechanism that will be managed by the Structures Monitoring Program).

By letter dated June 27, 2012, the staff issued RAI 3.5.2.4-5 requesting that the applicant explain why no AERMs or an AMP has been identified for rubber water stops exposed to air indoor uncontrolled environment that provide an intended function of flood barrier.

In its response dated July 25, 2012, the applicant stated that the rubber water stops are located in the expansion joint between the turbine building, foundation basemat and adjoining structures, and the expansion joint between the turbine building foundation basemat and the turbine building foundation. The applicant also stated that the rubber water stops are partially embedded in the concrete and the portion exposed to the air-indoor uncontrolled environment is located within the expansion joint gap a minimum of 3 feet below the top surface of the 6-foot-thick turbine foundation building basemat and the expansion joints containing the water stops are filled with an elastomeric material that is within scope of license renewal. The applicant further stated that the Structures Monitoring Program manages aging of the elastomer material within the seismic isolation joint, and although the maximum area temperature for the interior of the turbine building is 105 °F, the water stops are located in the lowest elevation of the building and are not exposed to temperatures above the GALL Report, Table IX.C, threshold for elastomers of 95 °F. In addition, the applicant stated that the water stop material is protected by the expansion joint configuration (i.e., surrounding concrete and expansion joint filler) and will not be exposed to an adverse environment (e.g., elevated temperature, ozone, oxidation, and radiation).

The staff finds the applicant's response acceptable because the rubber water stops are protected from adverse environments by the surrounding concrete and expansion joint filler; aging of the expansion joint filler and surrounding concrete will be managed by the Structures Monitoring Program that performs periodic visual examinations by qualified personnel using criteria derived from industry codes and standards, including ACI 349.3R, ACI 318, ANSI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable; and the proposal is consistent with GALL Report recommendations for managing aging of components as documented in item III.A6.TP-7 (SRP-LR Table 3.5.1 item 3.5.1-72). The staff's concern described in RAI 3.5.2.4-5 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).

3.5.3 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 <u>Aging Management of Electrical and Instrumentation and Controls System</u>

This section of the SER 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:

- high-voltage insulators
- non-EQ insulated cables and connections
  - cable connections (metallic parts)
  - electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
  - electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits
  - electrical and instrumentation control penetration cables and connections not subject to 10 CFR 50.49 EQ requirements
  - fuse holders (insulation material)
  - non-EQ fuse holder (metallic portion)
  - inaccessible power (400V to 35kV) cables (e.g., installed underground in conduit, duct bank or direct buried) not subject to 10 CFR 50.49 EQ requirements
  - inaccessible power (115kV) cables (e.g., installed underground in conduit, duct bank or direct buried) not subject to 10 CFR 50.49 EQ requirements
- switchyard bus and connections
- transmission conductors and connections

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 GALL Report was issued.

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 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 3.6-1 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/ 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 due to various mechanisms in accordance with 10 CFR 50.49	EQ is 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)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor (3.6.1-2)	Loss of material due to mechanical wear caused by wind blowing on transmission conductors	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to GGNS (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 due to presence of salt deposits or surface contamination	A plant-specific AMP 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	Not applicable	Not applicable to GGNS (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 due to corrosion	A plant-specific AMP is to be evaluated for ACSR	Yes	Not applicable	Not applicable to GGNS (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 due to oxidation or loss of preload	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.2.3)
Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air – outdoor (3.6.1-6)	Loss of material due to wind-induced abrasion; Increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to GGNS (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 due to wind-induced abrasion	A plant-specific AMP is to be evaluated for ACAR and ACSR	Yes	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to 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	Non-EQ Insulated Cables and Connections	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 due to 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	Non-EQ Instrumentation Circuits Test Review	Consistent with the GALL Report
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 due to moisture	Chapter XI.E3, “Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	No	Non-EQ Inaccessible Power Cables (400 V to 35 kV) and the 115 kV Inaccessible Transmission Cable	Consistent with the GALL Report (see SER Section 3.6.2.3.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to elastomer degradation	Chapter XI.E4, “Metal Enclosed Bus,” or Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.1.1)
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 due to the loosening of bolts caused by thermal cycling and ohmic heating	Chapter XI.E4, “Metal Enclosed Bus”	No	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.1.1)
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 due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	Chapter XI.E4, “Metal Enclosed Bus”	No	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.1.1)
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 due to general, pitting, and crevice corrosion	Chapter XI.E4, “Metal Enclosed Bus,” or Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ 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 galvanized steel; aluminum exposed to air – outdoor (3.6.1-15)	Loss of material due to pitting and crevice corrosion	Chapter XI.E4, “Metal Enclosed Bus,” or Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to GGNS (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 due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply); fatigue due to ohmic heating, thermal cycling, electrical transients	Chapter XI.E5, “Fuse Holders”	No	Not applicable	Not applicable to GGNS (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, controlled or uncontrolled (3.6.1-17)	Increased resistance of connection due to fatigue caused by frequent manipulation or vibration	Chapter XI.E5, “Fuse Holders” No AMP 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	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 due to 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	Non-EQ Cable Connections	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 due to corrosion of connector contact surfaces caused by intrusion of borated water	Chapter XI.M10, "Boric Acid Corrosion"	No	Not applicable	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 due to corrosion	None - for Aluminum Conductor Aluminum Alloy Reinforced (ACAR)	None	Not applicable	Not applicable to GGNS (see SER Section 3.6.2.1.1)
Fuse holders (not part of active equipment): insulation material, metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel, aluminum, exposed to air – indoor, controlled or uncontrolled (3.6.1-21)	None	None	No	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:

- Non-EQ Cable Connections
- Non-EQ Inaccessible Power Cables (400 V to 35 kV)
- Non-EQ Insulated Cables and Connections
- Non-EQ Instrumentation Circuits Test Review

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.

3.6.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.6.1, items 3.6.1-11 through 3.6.1-15, the applicant claimed that the corresponding items in the GALL Report are 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 3.6.1, items 3.6.1-16 and 3.6.1-17, the applicant stated that for fuse holder (not part of active equipment): metallic clamps exposed to air-indoor controlled, increased resistance of connection due to chemical contamination, corrosion, and oxidation; fatigue due to ohmic heating, thermal cycling, electrical transients and frequent manipulation or vibration are not applicable and no AMP is proposed. The applicant cited generic note I. The applicant also cited plant-specific note 601 that the fuse holders in the containment penetration panels (1BPZ1A, 1BPZ1B, 1BPZ2A, and 1BPZ2B) are subject to an AMR. The applicant stated that its evaluation of the fuses in the penetration protection cabinet fuse holder panels determined that the aging effects due to thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling, electrical transients, or mechanical fatigue caused by frequent manipulation (removal/replacement of the fuse), or vibration do not require aging management. GALL Report item VI.A.LP-23 and -31, "Fuse Holders (Not Part of Active Equipment): Metallic Clamp," identifies the aging effect or mechanism as increased resistance of connection due to chemical contamination, corrosion, oxidation; fatigue due to ohmic heating, thermal cycling, electrical transients; and increased resistance of connection due to 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 that are in the scope of license renewal do not require aging management. By letter dated June 22, 2012, the staff issued RAI 3.6.2.3-1 requesting the applicant to provide an evaluation that addresses each aging effect or mechanism identified in GALL Report, items VI.A.LP-23 and VI.A.LP-31. In response to the staff's request, in a letter dated July 23, 2012, the applicant stated that LRA Table 3.6.2-1, note 601, summarizes the evaluation of potential aging effects and mechanisms for metallic clamps of fuse holders. The evaluation of the aging effects and mechanisms identified in the GALL Report, item VI.A.LP-23 and item VI.A.LP-31 is further explained as follows.

VI.A.LP-23, Increased Connection Resistance Due to Chemical Contamination, Corrosion, and Oxidation

The location and mounting details of the penetration protection cabinet fuse holder panels were determined by review of GGNS drawings and documentation, and confirmed by plant walkdown. The auxiliary building rooms in which they are located have no sources of chemical contamination, and the fuse holders are housed in a protective enclosure to preclude this aging mechanism even if chemical contamination were possible. Therefore, based on their installed location and design configuration, increased connection resistance due to chemical contamination, corrosion, and oxidation is not considered an aging effect requiring management.

VI.A.LP-23, Increased Connection Resistance Due to Fatigue Caused by Ohmic Heating, Thermal Cycling, and Electrical Transients

GGNS power circuits are sized based on power cable ampacity considering ohmic heating and short-circuit conditions. The cable sizing is based on ampacity values from Insulated Power Cable Engineers' Association (IPCEA) P-46-426 "derating" factors for installation configuration, and the ability to carry 125 percent of full-load current. Ohmic heating is minimized by conservative cable sizing, which addresses rated temperature limitations. Therefore, ohmic heating of the fuse clamps is minimized. Without ohmic heating, thermal cycling on the metallic portion of the fuse clips is minimized. For electrical transients, GGNS electrical design ensures that stresses associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. Mechanical stress due to electrical faults is not considered a credible contributor to the effects of aging since such abnormal conditions are rare. Therefore, increased connection resistance due to fatigue caused by ohmic heating, thermal cycling, and electrical transients is not an aging effect requiring management.

VI.A.LP-31, Increased Resistance of Connection Due to Fatigue Caused by Frequent Manipulation or Vibration

A review of GGNS operating practices was performed to determine if fuses are frequently pulled. Fuses in the penetration protection cabinet fuse holder panels are rarely pulled, and the few that have been pulled are not pulled on a periodic or frequent basis. The location and mounting details of the penetration protection cabinet fuse holder panels were determined by review of GGNS drawings and documentation, and confirmed by plant walkdown. The documentation and walkdown confirmed that there are no direct sources of vibration in proximity to the fuse holder panels. The fuse holder panels are floor mounted in the auxiliary building penetration rooms. Therefore, increased connection resistance due to fatigue caused by frequent manipulation or vibration is not an aging effect requiring management.

The staff finds the finds the applicant response acceptable because it provides adequate justification for why each aging effect and mechanism identified in GALL Report items VI.A.LP-23 and VI.A.LP-31 are not applicable at GGNS. The staff finds that fatigue, mechanical stress, vibration, oxidation, and chemical contamination stressors are not applicable at GGNS. Fatigue is the aging effect for plants that manipulate fuses to deenergize circuits for plant testing. The fuses at GGNS are not routinely pulled or manipulated for plant testing. Therefore, fatigue and mechanical stresses due to testing are not an applicable aging effect. Cables are sized to 125 percent of full load current and ohmic heating is minimized by conservative cable sizing. Thermal cycling is minimized by the low ohmic heating. Therefore, the ohmic heating and thermal cycling are not significant stressors at GGNS. Stresses associated with mechanical stress due to electrical faults is not considered a credible aging stressor since such faults are infrequent and the fuse element 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 at GGNS. Vibration is an applicable aging stressor for fuse holders that are mounted on moving equipment such as motors, compressors, and pumps. GGNS fuses are not mounted on equipment subject to movement or vibration; they are mounted on concrete walls or support structures that do not vibrate. Therefore, vibration is not an applicable stressor at GGNS. Chemical contamination is a stress concentrator for fuse holders located near a chemical contamination source such as boron acid tanks. GGNS fuses are not exposed to chemical contamination or spills. During the staff audit, the staff walked down these fuses and noted that there is no potential source of chemical contamination in the areas near the fuse holders. Furthermore, fuse holders are enclosed in a protective panel that would provide protection against chemical attack. Therefore, chemical contamination is not an applicable aging effect at GGNS. The staff concern in RAI 3.6.2.3-1 is resolved.

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 that these items are not applicable to GGNS.

3.6.2.1.2 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed are not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed are not applicable are not applicable to GGNS.

As discussed in SER Section 3.4.2.1, 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 due to presence of any salt deposits and surface contamination, and loss of material due to mechanical wear caused by wind blowing on transmission conductors
- 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
- 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 EQ is a TLAA as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). The applicant also stated that evaluation of this TLAA is addressed separately in LRA Section 4.4. Section 4.4 of the staff's SE documents the review of the applicant's evaluation of this TLAA and the EQ electrical component program.

3.6.2.2.2 Reduced Insulation Resistance Due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material Due to Mechanical Wear Caused by Wind Blowing on Transmission Conductors

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 due to presence of salt deposits and surface contamination, and loss of material due to mechanical wear. The applicant stated that high-voltage insulators are subject to AMR if they are necessary for recovery of offsite power following a station blackout (SBO). Other high-voltage insulators are not subject to AMR since they do not perform a license renewal intended function. The applicant also stated that high-voltage insulators evaluated for GGNS license renewal are those used to support uninsulated, high-voltage electrical components such as transmission conductors and switchyard buses that are in the scope of license renewal.

The applicant stated that various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and in most areas washed away by rain. The glazed insulator surface aids this contamination removal. The applicant also stated that a large buildup of contamination could enable the conductor voltage to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near facilities that discharge soot or near the seacoast where salt spray is prevalent. GGNS is not located near the seacoast or near other sources of airborne particles. Therefore, reduced insulation resistance due to surface contamination is not an applicable aging effect for high-voltage insulators at GGNS.

Regarding loss of material due to mechanical wear, the applicant stated that mechanical wear is a potential aging effect for strain and suspension insulators subject to movement. Although this aging effect is possible, industry experience has shown transmission conductors do not normally swing and when subjected to a substantial wind, movement will subside after a short period. The applicant also stated that wear has not been apparent during routine inspections and is not a credible aging effect. There are no AERMs for GGNS high-voltage insulators.

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 due to salt deposits and surface contamination may occur in high-voltage insulators. The GALL Report 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 due to 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 applicant stated that GGNS is not located near the seacoast or near other sources of airborne particles. The applicant then concluded that reduced insulation resistance due to surface contamination is not an applicable aging effect for high-voltage insulators at GGNS. However, the applicant did not address the plant-specific operating experience at GGNS to support the applicant's claim that contamination is not significant at GGNS. By letter dated June 22, 2012, the staff issued RAI 3.6.2.2.2-1 requesting the applicant to confirm that there has been no occurrence of insulator flashover due to surface contamination at GGNS. In response to the staff request, in a letter dated July 23, 2012, the applicant stated that before LRA submittal, a review of GGNS operating experience for high-voltage insulators found no occurrence of insulator flashover. The applicant also stated that a subsequent review of up to June 30, 2012, also found no occurrence of insulator flashover for GGNS high-voltage insulators. The staff found the applicant response acceptable because the applicant addressed plant-specific operating experience and confirmed that there has been no occurrence of insulator flashover due to surface contamination. The staff concern in RAI 3.6.2.2.2-1 is resolved.

Since GGNS is not located in 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 GGNS supports the applicant's conclusion that contamination is not significant at GGNS because the applicant has indicated that there has been no occurrence of insulator flashover due to surface contamination.

The staff notes that EPRI 1013475 (License Renewal Handbook) 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, due to a substantial wind, they do not continue to swing for a long period of time once the wind has subsided. Transmission conductors typically are designed and installed not to swing significantly and cause wear due to wind-induced abrasion and fatigue. Furthermore, the applicant has not identified loss of material on high-voltage insulators due to mechanical wear during its routine inspection. Based on its review, the staff finds that mechanical wear aging effect of high-voltage insulators is not an aging effect requiring management at GGNS.

Based on the programs identified 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 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, -5, -6, and 7 addressing loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connections due to oxidation or loss of preload of transmission conductors and connections, and switchyard bus and connections.

The applicant stated that wind loading can cause transmission conductor vibration, or sway. Wind loading that can cause a transmission line and insulators to vibrate is considered in the design and installation. Loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not applicable aging effects in that they would not cause a loss of intended function if left unmanaged for the period of extended operation. The applicant also stated that operation of active switchyard components is also a potential contributor to vibration and resulting wear. Switchyard bus is connected to active equipment by short sections of flexible conductors. The flexible conductors withstand the minor vibrations associated with the active switchyard components. The flexible conductors are part of the switchyard bus commodity group. Vibration is not applicable since flexible conductors connecting switchyard bus to active components eliminate the potential for vibration.

The applicant further stated a review of plant-specific operating experience did not identify any unique aging effects for transmission conductors. Therefore, loss of material due to wear of transmission conductors is not an aging effect requiring management at GGNS.

The applicant stated that transmission conductors are subject to AMR if they are necessary for recovery of offsite power following an SBO. At GGNS, transmission conductors from the GGNS 115 kV switchyard to the ESF transformer (ESF 12) and from the GGNS 115 kV switchyard to the Port Gibson substation support recovery from an SBO. Other transmission conductors are not subject to an AMR since they do not perform a license renewal intended function.

The applicant stated that tests performed by Ontario Hydro showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. GGNS ESF 12 transformer high-voltage side is connected to the 115 kV switchyard through overhead transmission lines. The 115 kV switchyard is connected to the Port Gibson substation by overhead transmission lines. These 115 kV overhead transmission conductors are 336.4 thousand circular mils (MCM) 26/7 ACSR conductors. This specific conductor construction type was included in the Ontario Hydroelectric test, so the results of this test are representative of the GGNS 115 kV overhead transmission conductors. The 336.4 MCM 26/7 ACSR transmission conductor tested in the Ontario Hydro test, as documented in the companion paper, “Aged ACSR Conductors, Part II - Prediction of Remaining Life,” bounds the GGNS transmission conductors.

The applicant also stated that the National Electrical Safety Code (NESC) requires that tension on installed conductors be less than 60 percent of the ultimate conductor strength. The applicant stated that these requirements were reviewed for the specific transmission conductors included in the scope of license renewal. The applicant further stated that evaluation of the conductor type with the smallest ultimate strength margin (4/0 ACSR, 6/1) in the NESC illustrates the conservative nature of the design of transmission conductors. The 4/0 ACSR 6/1 conductor has only one steel reinforcement conductor, so the impacts of corrosion on this one steel reinforcement conductor is more severe than a transmission conductor with multiple steel reinforcement conductors.

The applicant stated that the ultimate strength and the NESC required heavy load tension capability of 4/0 (212 MCM) ACSR 6/1 are 8,350 lbs and 2,761 lbs respectively. The actual margin for a 4/0 ACSR 6/1 conductor between the NESC heavy load and the ultimate strength is 5,589 lbs (i.e., there is a 67 percent of ultimate strength margin). The Ontario Hydro study showed a 30 percent loss of composite conductor strength in an 80-year-old conductor. In the case of the 4/0 ACSR 6/1 transmission conductors, a 30 percent loss of ultimate strength would mean that the 80-year ultimate strength (30 percent loss) of 4/0 (212 MCM) ACSR 6/1 would be 5,845 lbs. Based on the NESC criteria, an 80-year-old 4/0 ACSR 6/1 conductor could have an installed tension of 3,507 lbs (60 percent of 5,845 lbs), which is a margin of 746 lbs, (i.e., there would be a 13 percent of ultimate strength margin for an 80-year-old cable). The applicant also stated that actual margin for an 80-year 4/0 ACSR 6/1 conductor between the NESC heavy load and the aged ultimate strength would be 3,084 lbs (i.e., there would still be a 53 percent margin to the aged ultimate strength). Therefore, there would still be a 53 percent ultimate strength margin based on the actual conductor strength after 80 years of service compared to the 40 percent ultimate strength margin allowed by the NESC for a new cable. The applicant further stated that the 4/0 ACSR conductor type has the lowest initial design margin of transmission conductors included in the Ontario Hydro test, so this example bounds in-scope GGNS transmission conductors. This example illustrates with reasonable assurance that transmission conductors will have ample strength through the period of extended operation.

The applicant stated that a review of industry operating experience and NRC generic communications related to the aging of transmission conductors ensured that no additional aging effects exist beyond those previously identified. A review of plant-specific operating experience did not identify any aging effects for transmission conductors at GGNS.

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 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 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 GGNS.

The staff noted that wind borne particulates have not been shown to be a contributor to loss of material at GGNS 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 aging effect requiring management for transmission conductors and connections at GGNS.

The staff noted that the design of switchyard bolted connections precludes torque relaxation. The use of stainless steel Belleville washers is the industry standard to preclude torque relaxation. GGNS 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 and Application Guide”). Based on the review, the staff finds that loosening of the switchyard bolted connections is not an aging effect requiring management at GGNS.

The bolted connections and washers at GGNS 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 due to oxidation or loss of preload are not significant AERMs for transmission conductor and switchyard bus connections at GGNS.

The Ontario Hydro study showed about 30 percent loss of conductor strength of an 80-year-old ACSR conductor due to 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 includes consideration of ½ inch of radial ice and 4 lbs per square feet (psf) wind. Based on the Ontario Hydro study, a loss of conductor strength of 30 percent on ACSR conductors would mean that the conductor strength would be 5,845 lbs (8,350 lbs x 0.7 = 5,845 lbs). The ratio between the heavy loading and the ultimate conductor strength would be approximately 53 percent (2,761 lbs/5,845 lbs). The NESC requires that tension on the installed conductor be a maximum of 60 percent of the ultimate conductor strength. The tension (heavy load) of a typical transmission conductor would not exceed the NESC maximum requirement of 60 percent of the ultimate conductor strength. The 4/0 ACSR conductor type has the lowest initial design margin of transmission conductors as compared to the 336.4 kcmil, 30/7 ACSR conductors used in the test sample in the Ontario Hydro Study. The 4/0 ACSR 6/1 conductor has only one steel reinforcement conductor, so the impact of corrosion on this one steel reinforcement conductor is more severe than a transmission conductor with multiple steel reinforcement conductors. The staff determined that the example the applicant provided bounds the in-scope GGNS transmission conductors. With a 30 percent loss of conductor strength, there is still ample margin between the NESC requirements and the actual conductor strength. Furthermore, the applicant has confirmed that plant-specific operating experience did not identify any aging effects for transmission conductors at GGNS. Therefore, the staff finds that loss of conductor strength due to corrosion is not a significant aging effect requiring management at GGNS.

Based on the programs identified 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 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.

3.6.2.3.1 Electrical and I&C Components - 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 and I&C components component groups.

<u>115 kV Inaccessible Transmission Cables</u>. In LRA Table 3.6.2-1, the applicant stated that conductor insulation for inaccessible power cables (115 kV) not subject to 10 CFR 50.49 requirements exposed to significant moisture will be managed for reduced insulation resistance by 115 kV Inaccessible Transmission Cable AMP. The applicant cited generic note 602, which states the 115 kV Inaccessible Transmission Cable Program as a new plant-specific program; however, this program is based on the NUREG-1801, XI.E3 program.

The staff reviewed the associated items in the LRA and considered whether the aging effects the applicant proposed constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant addressed insulation resistance for this component, material, and environment combination in other AMR items in LRA Tables 3.6.2-1, conductor insulation for inaccessible power cables (400 V to 35 kV) not subject to 10 CFR 50.49 EQ requirements. Based on its review of GALL Report AMP XI.E3, which states that when a power cable is exposed to wet, or submerged, or other adverse environmental condition for which it was not designed, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. 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 applicant's 115 kV Inaccessible Transmission Cable Program is documented in SER Section 3.0.3.2.1. The staff finds the applicant's proposal to manage aging using the 115 kV Inaccessible Transmission Cable Program acceptable because inspection for water collection will prevent inaccessible transmission cables from being exposed to significant moisture and testing will provide an indication of the condition of the conductor insulation.

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 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 that there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed license 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 (US) Nuclear Regulatory Commission (NRC) staff's (the staff) evaluation of the applicant's basis for identifying those plant-specific or generic calculations and 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 current licensing basis (CLB) calculations and 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 Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(2).

Pursuant to the requirements in 10 CFR 54.21(c)(1), an applicant for license renewal must list calculations and analyses in the CLB that conform to the definition of a TLAA in 10 CFR 54.3, which states that a licensee's calculations and analyses are TLAAs if they meet all six of the following TLAA identification criteria:

(1) involve systems, structures, and component (SSCs) within the scope of license renewal, 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, for example, 40 years;

(4) were determined to be relevant by the licensee 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 delineated in 10 CFR 54.4(b); and

(6) are contained or incorporated by reference in the CLB.

For each TLAA, the applicant shall demonstrate:

(i) The analysis remains valid for the period of extended operation;

(ii) The analysis has been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for 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 in effect and are based on a TLAA. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of these 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 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 SRP-LR to see if they are applicable to and included as part of the applicant's CLB.

The applicant stated that the process it used for its TLAA identification is consistent with the guidance of Nuclear Energy Institute (NEI) 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—the License Renewal Rule."

The applicant stated that it reviewed the following plant-specific or generic sources (documents or records): (a) updated final safety analysis report (UFSAR), (b) technical specifications (TS) and bases, (c) Technical Requirements Manual, (d) extended power uprate LAR, (e) BWRVIP documents referenced in the UFSAR or in docketed licensing correspondence, (f) industry topical reports (relevant documents referenced in the UFSAR or in docketed licensing correspondence), (g) fire protection documents, (h) Inservice Inspection Program documents, (i) NRC SERs, and (j) docketed licensing correspondence.

The applicant provides its list of TLAAs in LRA Table 4.1-1, "List of TLAAs." In this table, the applicant indicates that the following analyses 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 Analyses in LRA Section 4.2
- Metal Fatigue Analyses in LRA Section 4.3
- Environmental Qualification (EQ) Analyses of Electrical Components in LRA Section 4.4
- Containment Liner Plate, Metal Containment, and Penetrations Fatigue Analysis in LRA Section 4.6
- Plant-specific TLAAs in LRA Section 4.7

The applicant also indicates in LRA Table 4.1-1 that "Concrete Containment Tendon Prestress Analysis" is not a TLAA, as described in LRA Section 4.5 (See SER Section 4.1.2.1.2).

The applicant provides its bases for accepting these TLAAs in accordance either with 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of LRA Sections 4.2–4.4, 4.6, and 4.7.

The applicant indicates in LRA Table 4.1-2 that the following generic TLAAs listed in Section 4.1 of the SRP-LR Table 4.1-2 are TLAAs for the LRA:

- Reactor vessel neutron embrittlement (LRA Section 4.2)
- Metal fatigue (LRA Section 4.3)
- Environmental qualification of electrical equipment (LRA Section 4.4)

The applicant also indicates in LRA Table 4.1-2 that the following generic TLAAs listed in Section 4.1 of the SRP-LR Table 4.1-2 are not part of the CLB, and therefore they are not included in the LRA:

- Concrete containment tendon prestress analysis
- Inservice local metal containment corrosion analyses

The applicant indicates in LRA Table 4.1-2 that the following potential plant-specific TLAAs listed in SRP-LR, Section 4.1, Table 4.1-3, are TLAAs for the LRA:

- Transient cycle count assumptions for the reactor vessel (RV) internals (RVI)
- Ductility reduction of fracture toughness for the RVI
- Fatigue analysis for the containment liner plate
- Containment penetration pressurization cycles

The applicant indicates in LRA Table 4.1-2 that the following potential plant-specific TLAAs listed in SRP-LR, Section 4.1, Table 4.1-3, are not part of the CLB, and therefore they are not included in the LRA:

- Intergranular separation in the heat-affected zone of RV low-alloy steel under austenitic stainless steel (SS) cladding analyses
- Low temperature overpressure protection analyses
- Fatigue analysis for the main steam supply lines to the turbine-driven auxiliary feedwater (AFW) pumps
- Fatigue analysis of the reactor coolant pump (RCP) flywheel
- Fatigue analysis of the polar crane
- Flow-induced vibration endurance limit for the RVI
- Leak-before-break
- Metal corrosion allowance
- Inservice flaw growth analyses that demonstrate structure stability for 40 years

4.1.1.2 Identification of Regulatory Exemptions

LRA Section 4.1.2 states no exemptions were identified that will remain in effect for the period of extended operation and are based on a TLAA.

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 TLAA 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 Calculations and Analyses in the CLB Conforming to 10 CFR 54.3 TLAA Criteria

The staff confirmed that the applicant included its TLAAs for the RPV neutron embrittlement analyses in the applicable referenced subsections of LRA Section 4.2, which includes the TLAAs for the assessment of pressure-temperature (P-T) limits, upper-shelf energy (USE), RV circumferential weld inspection relief, RV axial weld failure probability, and RPV core reflood thermal shock analysis. These analyses were included as TLAAs in the LRA because: (1) the analyses are mandated by applicable NRC requirements (e.g., 10 CFR Part 50, Appendix G, for USE and P-T limit requirements, and 10 CFR Part 50, Appendix H, for RPV surveillance capsule neutron dosimetry and fracture toughness impact test analyses) or industry-recommended studies (e.g., the reflood analysis recommended by General Electric [GE]); and (2) the 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 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 accepting these TLAAs in accordance with 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, as previously referenced in the Summary of Technical Information above. These analyses were included as TLAAs in the LRA because: (1) the analyses are mandated by applicable design rules (e.g., those in Section III of the ASME Code or in the American National Standards Institute (ANSI) B31.1 design code) or the applicant implemented the analyses as part of its commitments to applicable NRC generic communications (e.g., the applicant conservatively treats environmentally assisted fatigue [EAF] for limiting Class 1 locations as a TLAA in the LRA and addresses this analysis consistent with the resolution of Generic Safety Issue [GSI] No. 191) and (2) the 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 accepting these TLAAs in the applicable subsections of SER Section 4.3.

The staff confirmed that the applicant included its TLAA for environmental qualification (EQ) of electrical equipment in LRA Section 4.4. This analysis was included as a TLAA because: the analysis is mandated by the requirements in 10 CFR 50.49 and 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 TLAA for EQ of electrical equipment was in conformance with the staff recommendations in SRP-LR Sections 4.1 and 4.4, which provide the bases for identifying EQ analyses for electrical components as TLAAs in accordance with 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of the TLAA for EQ of electrical equipment is acceptable because it is in compliance with 10 CFR 54.21(c)(1). The staff evaluates the applicant's basis for accepting the TLAA for EQ of electrical equipment in SER Section 4.4.

The staff confirmed that the applicant included its TLAAs for the containment liner plate, metal containment structures, and containment penetrations fatigue analyses in LRA Section 4.6. Cumulative usage factors (CUFs) calculated for the containment liner and quencher components are described in LRA Section 4.6.1 and listed in Table 4.6-1, and CUFs calculated for the containment penetrations are evaluated in LRA Section 4.6.2 and identified in LRA Table 4.6-2. These analyses were included as TLAAs in the LRA because: (1) the analyses are mandated by the applicable fatigue calculation or fatigue waiver rules in Section III of the ASME Code or were performed as part of applicable design calculations and (2) 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 accepting these TLAAs in SER Sections 4.6.1 and 4.6.2.

The staff confirmed that the applicant included the following plant-specific TLAAs for the LRA in LRA Section 4.7: (1) erosion of the MSL flow restrictors (LRA Section 4.7.1), (2) determination of intermediate high-energy line break (HELB) locations (LRA Section 4.7.2), and (3) fluence effects (ductility reduction) analyses for RVI components (LRA Section 4.7.3). The staff noted that the applicant's identification of these TLAAs was consistent 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 accepting these plant-specific TLAAs in the applicable subsections of SER Section 4.7.

4.1.2.1.2 Evaluation of Applicant's List of Calculations and Analyses in the CLB That Do Not Meet the Six Criteria for TLAAs in 10 CFR 54.3 and the Absence of Generic or Potentially Applicable Plant-Specific TLAAs Due to Absence in the CLB

<u>Absence of a TLAA on Concrete Containment Tendon Prestress</u>. In LRA Tables 4.1-1 and 4.1-2, the applicant identified that the CLB does not include a concrete containment tendon prestress analysis. The applicant stated that its containment design does not include tendons.

SRP-LR Table 4.1-2 identifies the containment tendon prestress 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 noted that the UFSAR Section 3.8 defines the containment as a concrete containment structure that is designed with three basis subsections: (1) a flat circular foundation mat, (2) a right circular containment cylinder, and (3) a hemispherical containment dome. The staff also noted that UFSAR Section 3.8 indicates that the containment mat, cylinder, and dome are constructed of cast-in-place, conventionally reinforced concrete, and that UFSAR Section 3.8.1 provides a full description of the reinforcement bases for the concrete containment structure. The staff confirmed, from its review of UFSAR Section 3.8.1, that the containment does not use prestressed 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 prestress TLAA because the staff has confirmed that: (a) the containment does not include prestressed tendons as the containment reinforcement basis and (b) the generic concrete containment prestress analysis in SRP-LR Table 4.1-2 is not applicable to the applicant's CLB [Criterion 6 of 10 CFR 54.3(a)].

<u>Absence of a TLAA on Inservice Local Metal Containment Corrosion</u>. In LRA Table 4.1-2, the applicant identified that the CLB does not include any inservice local metal containment corrosion analyses for the containment structure. The applicant stated the containment is a GE

Mark III containment design and that the CLB does not include any corrosion analysis associated with this type of containment design. 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 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 the staff has confirmed that: (a) the applicant's CLB does not include any metal corrosion analyses for the concrete containment structure, other seismic Category 1 structures, or their subcomponents and (b) the localized metal containment structure corrosion analysis reference in SRP-LR Table 4.1-2 is not applicable to the applicant's CLB [Criterion 6 of 10 CFR 54.3(a)].

<u>Absence of a TLAA on Intergranular Separation in the Heat-Affected Zone of Reactor Vessel Low-Alloy Steel Under Austenitic Stainless Steel Cladding</u>. 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 a plant-specific RPV underclad cracking analysis may qualify as a TLAA if such an analysis is included in the applicant's CLB. The relevant SRP-LR recommendations are only applicable to RPV SA-508, Class 2 forgings that were welded to the RPV cladding using a high heat weld input process that resulted in large-grained weld microstructures. 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 for the welding practice used for the RPV-to-cladding welds was appropriately controlled during the welding process such that it would result in a fine-grained deposited weld metal. NRC Regulatory Guide (RG) 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components," provides the staff's 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 RPV is fabricated primarily from low alloy steel plates and forgings. The staff also noted that the UFSAR indicated that the low alloy steel RPV plates were ordered to SA 533, Grade B, Class 1 specifications and that the RPV forging components were fabricated to SA 508, Class 2 specifications. SER Section 3.1.2.2.5 documents the staff's evaluation of the applicant's response to request for additional information (RAI) 4.1-1. In its evaluation of the applicant's response to RAI 4.1-1, the staff noted that UFSAR Section 5.3.1.6.45.3.1.4.1.2 identifies that the forging-to-cladding welds for all RPV low-alloy steel forging components were fabricated from materials and welding methods that conformed to the regulatory position in RG 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components," and resulted in fine-grain weld microstructures. Thus, the staff confirmed that the applicant used weld practices in the fabrication of the RPV-to-cladding welds that are consistent with the regulatory position in Section C of RG 1.43. Therefore, the staff has determined that the applicant has implemented applicable design welding practices for precluding underclad cracking in the RPV as the basis for addressing potential underclad cracking in the RPV forging-to-cladding welds and that the design basis does not rely on any time dependent analysis to address this RPV cracking issue.Based on this review, the staff concludes that the LRA does not need to include a TLAA on intergranular separation as described in SRP-LR Table 4.1-3 because the staff has confirmed that: (a) the forging-to-cladding welds for all SA-508, Class 2 low alloy steel forging components in the RPV were fabricated from materials and welding methods that resulted in fine-grain microstructures and (b) the applicant's CLB does not contain or rely on any time-dependent analysis as the basis for addressing underclad cracking (i.e., intergranular separations) in the RPV's forging-to-cladding welds.

Absence of a TLAA on Low Temperature Overpressure Protection. In LRA Table 4.1-2, the applicant identified that the CLB does not include a low-temperature overpressure protection (LTOP) analysis for the RPV and reactor coolant pressure boundary (RCPB). The applicant stated that this analysis is not applicable to boiling water reactor (BWR) designs.

SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific LTOP analysis that qualifies as a TLAA for the applicant's LRA. The relevant SRP-LR recommendations are only applicable to the LTOP systems in pressurized water reactor (PWR) designs. The SRP-LR guidance is not applicable to BWR designs because they 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 UFSAR Chapter 1 defines the reactor as a GE-designed BWR that is built to the GE BWR-6 model specifications and protected by a GE Mark III containment design. The staff also confirmed that the BWR-6 design does not include LTOP systems. Therefore, the staff concludes that the LRA does not need to include a plant-specific LTOP TLAA because the staff has confirmed that: (a) the BWR-6 reactor design does not include a LTOP system and (b) the TLAA referenced in SRP-LR Table 4.1-3 for LTOP systems is not applicable to the applicant's CLB [Criterion 6 of 10 CFR 54.3(a)].

Absence of a TLAA on Fatigue Analysis for Main Steam Supply Lines to Auxiliary Feedwater Pumps. In LRA Table 4.1-2, the applicant identified that the CLB does not include a fatigue analysis for main steam lines that supply steam to steam-driven AFW pumps.

The applicant stated that its design does not include AFW pumps. SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific metal fatigue analysis for AFW pump main steam supply lines that qualifies as a TLAA for the applicant's LRA. The relevant SRP-LR recommendations are only applicable to PWRs with designs that include steam-driven AFW pumps. The SRP-LR guidance is not applicable to BWR designs because they 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 UFSAR Chapter 1 defines the reactor as a GE-designed BWR that is built to the BWR-6 model specifications and protected by a GE Mark III containment design. The staff also confirmed that the BWR-6 design does not include any AFW systems or AFW 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 the staff has confirmed that: (a) the BWR-6 reactor design does not include AFW systems or AFW pumps and (b) the TLAA referenced in SRP-LR Table 4.1-3 for steam-driven AFW pump steam supply lines is not applicable to the applicant's CLB [Criterion 6 of 10 CFR 54.3(a)].

Absence of a TLAA on Fatigue Analysis 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 analysis for RCP flywheels. The applicant stated that it is a BWR and that the recirculation pumps in the RCPB recirculation loops are not designed with flywheels.

SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific cycle-dependent fatigue or flaw tolerance analysis for RCP flywheels that qualifies as a TLAA for the applicant's LRA. The SRP-LR recommendations are only applicable to RCP flywheels in PWR designs. The relevant SRP-LR guidance is not applicable to BWR designs 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 UFSAR Chapter 1 defines the reactor as a GE-designed BWR that is built to the BWR-6 model specifications and protected by a GE Mark III containment design. The staff also confirmed that the applicant's BWR-6 design does not include AFW systems or AFW pumps. Therefore, the staff concludes that the LRA does not need to include a plant-specific TLAA for RCP flywheels because the staff has confirmed that: (1) the BWR-6 reactor design does not include RCP flywheels and (2) the TLAA referenced in SRP-LR Table 4.1-3 for RCP flywheels is not applicable to the applicant's CLB [Criterion 6 of 10 CFR 54.3(a)].

<u>Absence of a TLAA on Fatigue Analysis of Polar Crane</u>. In LRA Table 4.1-2, the applicant identified that the CLB does not include any analysis for the polar crane that would need to be identified as a TLAA in the LRA. The applicant stated that the relevant analysis of the polar crane is not based on time-dependent assumptions defined by the current operating term such as 40 years of the plant; therefore, it does not conform to the definition of a TLAA in 10 CFR 54.3.

SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific cycle-dependent analysis for polar cranes that qualifies as a TLAA for the applicant's LRA.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "absence of a TLAA" basis. The staff noted that UFSAR Chapter 9 identifies that the facility is designed with the following types of cranes: (a) a polar crane; (b) a containment hatchway crane; (c) a spent-fuel cask crane; and (d) a new fuel handling crane. The staff noted that UFSAR Chapter 9 analyzed these cranes based only on an analysis of the limiting load that could be supported by a crane lift without initiating the occurrence of an associated crane failure or load drop event. The staff did not find any time-dependent loading analyses for the cranes that might need to be identified as TLAAs for the LRA.

The staff noted that UFSAR Chapter 9 identifies that the polar crane was designed and analyzed to the Crane Manufacturers Association of America, Inc. (CMAA-70) design specification. The staff noted that the UFSAR did not specify which design specifications were used for the design and analysis of the containment hatchway crane, spent-fuel cask crane, or new fuel handling crane. By letter dated June 5, 2012, the staff issued RAI 4.1-2, which requested the applicant to identify which design specifications were used for the design and analysis of the containment hatchway, spent-fuel cask, and new fuel handling cranes. The staff also asked the applicant to clarify whether the specific design specifications for the containment hatchway, spent-fuel cask, and new fuel handling cranes, and CMAA-70 specification for the polar crane, would have required the applicant to establish a limit on the number of times the cranes could be used to lift their limiting loads, and if so, why the time-dependent cycle analyses for the cranes would not need to be identified as TLAAs for the LRA, when assessed against the six criteria for identifying TLAAs in 10 CFR 54.3.

In its response to RAI 4.1-2, by letter dated July 3, 2012, the applicant stated that the spent fuel cask and new fuel handling cranes were designed to meet applicable criteria of the CMAA-70, and the containment hatchway crane load-bearing parts were analyzed for all applicable loads in accordance with the requirements of the American Institute of Steel Construction (AISC) Steel Construction Manual, 7th Edition. The applicant also stated that the spent fuel cask crane, new fuel handling crane, and polar crane are designed for a minimum of 100,000 cycles in accordance with CMAA-70, and that the containment hatchway crane does not have an established limit on the number of times the crane could be used to lift a limiting load. The applicant further stated that the allowable cycles based on CMAA-70 allowable stress ranges are not time-limited and are well above the estimated number of cycles for the spent fuel cask crane, new fuel handling crane, and polar crane during 60 years of plant operation and, therefore, there are no TLAAs associated with crane cycles.

The staff reviewed the applicant's response and noted that the spent fuel cask crane, new fuel handling cranes, and polar crane were designed for a minimum of 100,000 cycles in accordance with CMAA-70. The staff noted that the CMAA-70 allowable stress ranges are not time-limited. However, the staff also noted that the monitoring of loading cycles against the upper bound design limit for loading cycles is a time-dependent assessment defined by the life of the plant. Therefore, the staff did not have sufficient information to conclude that these assessments for these cranes do not need to be identified as TLAAs for the LRA because the analyses do include a time-dependency.

By letter dated September 7, 2012, the staff issued follow-up RAI 4.1-2a, in part (a) requesting, the applicant to provide justification on why the analysis of loading cycles for spent fuel cask cranes, new fuel handling cranes, and polar crane would not need to be identified as TLAAs for the LRA when compared to the six criteria for defining TLAAs in 10 CFR 54.3(a). In part (b) of this RAI, the staff asked the applicant to amend the LRA appropriately if it was determined that the analyses of loading cycles for the spent fuel cask cranes, new fuel handling cranes, and polar crane should have been identified as TLAAs, based on a comparison to the six criteria for identifying TLAAs in 10 CFR 54.3(a) and the TLAA identification requirements in 10 CFR 54.21(c)(1), and to disposition the TLAAs accordingly in compliance with requirements in 10 CFR 54.21(c)(1)(i), (ii), or (iii).

The applicant responded to RAI 4.1-2a in a letter dated October 2, 2012. In its response, the applicant resolved the request raised in RAI 4.1-2a by amending the LRA to identify the analyses for the spent fuel cask crane, new fuel handling crane and polar crane as TLAAs for the LRA. Specifically, the applicant made the following changes to the LRA that the staff confirmed are in compliance with the requirements in 10 CFR Part 54 and also consistent with recommendations in the GALL Report and SRP-LR:

- With regard to compliance with the TLAA identification requirement in 10 CFR 54.21(c)(1) and consistency with the recommendations for plant-specific TLAAs in SRP-LR Section 4.7, the staff confirmed that the applicant amended LRA Section 4.7 to include TLAA Section 4.7.4, "Fatigue Analysis of Cranes," which provides the applicant's evaluation of the spent fuel cask crane, new fuel handling crane and polar crane analyses and discusses the applicant's basis for acceptance the TLAA for these cranes in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(i).
- With regard to compliance with the UFSAR supplement inclusion requirements in 10 CFR 54.21(c)(2), the staff confirmed that the applicant amended LRA Appendix A, "Updated Final Safety Analysis Report Supplement," to include LRA Section A.2.5.4, "Fatigue Analysis of Cranes," which provides the applicant's UFSAR supplement

summary description on the TLAA for the fuel cask crane, new fuel handling crane, and polar crane.

- With regard to consistency with the recommendations in SRP-LR Section 4.1, the staff confirmed that the applicant amended LRA Table 4.1-1, "List of GGNS [Grand Gulf Nuclear Station] TLAAs and Resolution," to include an item on "Fatigue Analysis of Cranes," indicating acceptance of the TLAA and referring to the TLAA evaluation in LRA Section 4.7.4.
- With regard to consistency with the recommendations in SRP-LR Table 4.1-3, the staff confirmed that the applicant amended LRA Table 4.1-2, "Comparison of GGNS TLAA to NUREG-1800 TLAA," to indicate that the "Fatigue Analysis of polar crane," as listed in SRP-LR Table 4.1-2 is applicable to the GGNS CLB and to refer to the evaluation of the GGNS polar crane in LRA Section 4.7.4.
- With regard to consistency with the recommendations in SRP-LR Section 3.5.2.2, the staff confirmed that the applicant amended LRA Section 3.5.2.3, "Time Limited Aging Analyses," to identify that the spent fuel cask crane, new fuel handling crane and polar crane analyses are within a scope of a TLAA in the LRA.
- With regard to consistency with the recommendations in aging management review (AMR) Item 1 in SRP-LR Table 3.3-1, the staff confirmed that the applicant amended AMR Item 3.3.1-1 in LRA Table 3.3.1 to identify that the analysis of fatigue for steel crane structural girders is a TLAA in the LRA.
- With regard to consistency with the recommendations in GALL Report Table VII.B, the staff confirmed that the applicant amended AMR Item 3.3.1-1 in LRA Table 3.5.2-1, "Containment Building," to include a TLAA-based AMR item for steel crane structural girders that are exposed to an uncontrolled indoor air environment.

The staff finds that the applicant's amended basis is acceptable because the staff has confirmed that: (a) the applicant amended the LRA to appropriately identify the analyses for the spent fuel cask crane, new fuel handling crane and polar crane as a TLAA in the LRA, (b) the applicant has made the appropriate changes to the LRA needed to be consistent with corresponding sections and tables in the GALL Report and SRP-LR, and (c) the changes made by the applicant are in compliance with the Commission's TLAA identification requirements in 10 CFR 54.21(c)(1) and Commission's UFSAR supplement summary description requirements in 10 CFR 54.21(c)(2). The staff evaluation of the TLAA for the spent fuel cask crane, new fuel handling crane and polar crane is given in SER Section 4.7.4. The staff's evaluation of the amendment of LRA Section 3.5.2.3 is given in SER Section 3.5.2.3. RAI 4.1-2a is resolved.

In relation to the applicant's RAI 4.1-2 response for the containment hatchway crane, the staff noted that the crane rails were required to be designed in accordance with requirements for crane rail designs in Section 1 of the AISC standard and that the load-bearing parts of the cranes were required to be evaluated in accordance with the specifications in Section 5 of the AISC standard. This includes evaluation of the load-bearing parts for possible fatigue loading conditions per Chapter 5, Section 1.7 of the AISC standard and Section 1.7 of Appendix B of the AISC standard. Specifically, the staff noted that Table B1, "Number of Loading Cycles," in Appendix B of the AISC standard would establish a loading condition for each of the crane load-bearing parts based on the following load cycle ranges: (a) 20,000–100,000 loading cycles for loading condition 1, (b) 100,000–500,000 loading cycles for loading condition 2, (c) 500,000-2,000,000 loading cycles for loading condition 3, and (d) over 2,000,000 loading cycles for loading condition 4. The staff noted that Tables B2 and B3 in Appendix B of the AISC specification then use the loading condition category for each of the load-bearing parts to establish maximum allowable stresses for these components.

The staff also noted that UFSAR Section 9D.3.1 confirms that the load-bearing parts of the containment hatchway crane were designed and evaluated to the design specifications in the AISC Steel Construction Manual, 7th Edition, and the evaluation of the crane was used to perform structural modifications and “derating” of the containment hatchway crane. However, the staff noted that the UFSAR Section 9D.3.1 did not identify specifically what modifications were made to the design of this crane or which criteria in the AISC standard or other NRC requirements applicable to the crane were specifically derated per the crane analysis, or whether the specific analysis used for the “derating” purpose or purposes was based on a TLAA. Therefore, the staff did not have sufficient information to conclude that evaluation of the containment hatchway crane did not include any cycle dependent analyses that conformed to the definition of a TLAA in 10 CFR 54.3(a). The staff did not have sufficient information to determine whether the number of load cycles established for the hatchway crane in the design basis would have required the applicant to analyze the crane for fatigue loads based on the analysis basis established for fatigue loadings in Appendix B of the AISC standard; and, if so, why the counting of load cycles for the cranes against the limits set for the cranes would not be time-dependent as defined by the life of the plant. The staff also did not have sufficient information to determine whether the AISC standard subpart evaluation or evaluations used for the crane “derating” objectives was based on a TLAA.

Therefore, by letter dated September 7, 2012, the staff issued follow-up RAI 4.1-2b, requesting, in part (a) of the RAI, that the applicant to provide a basis on how the load-bearing parts for the containment hatchway crane were assessed for potential fatigue bearing loads, or else provide why the crane bearing would not have been required to be assessed for fatigue if fatigue analyses were not performed for the containment hatchway crane load-bearing parts as part of the design basis. In part (b) of this RAI, the staff asked the applicant to provide a basis on why such fatigue analyses would not need to be identified as TLAAs for the LRA if the CLB did include applicable fatigue analyses for the containment hatchway crane load-bearing parts. In part (c) of the RAI, the staff asked the applicant to identify all modifications of the containment hatchway crane that were made per the AISC standard evaluation of the crane. The staff also asked the applicant to identify the specific AISC standard subpart evaluation or evaluations used to “derate” this crane and to identify the specific AISC criteria or other NRC requirements that the evaluation or evaluations used to “derate” and to justify such a basis. The staff also asked the applicant to explain and justify why the specific AISC standard subpart evaluation or evaluations used for “derating” purpose would not need to be identified as a TLAA when compared to the six criteria for defining TLAAs in 10 CFR 54.3(a).

The applicant provided its response to RAI 4.1-2b in a letter dated October, 2, 2012. In its response, the applicant clarified that the containment hatchway crane is a non-safety related truck bed crane that contains a hydraulically operated boom that was purchased and mounted to a pedestal inside containment. The applicant stated that the analysis referred to in UFSAR Section 9D.3.1 is a supplemental analysis that was performed to demonstrate that the crane would not cause damage to safety-related equipment in the vicinity by failing during a postulated seismic event. The applicant stated that the supplemental AISC Standard analysis referred to in UFSAR Section 9D.3.1 was only performed to demonstrate that the containment hatchway would satisfy Seismic II over I structural requirements. The applicant stated that the “derating” of the containment hatchway crane referred to in UFSAR Section 9D.3.1 involved a decision by Entergy to set a maximum allowable load value for the crane to a value less than the maximum allowable load recommended for the crane by its vendor. The applicant also stated the modifications of the containment hatchway crane referred to in the UFSAR were the addition of stiffeners at certain crane locations and the use of 1-inch diameter A490 bolts to attach the crane to its pedestal.

The applicant also clarified that the seismic analysis of the containment hatchway crane involved reconciliation against the following sections in the AISC Standard: (a) Section 1.5.1.2, "Shear"; (b) Section 1.5.13, "Compression"; (c) Section 1.5.1.4, "Bending"; (d) Section 1.9.1, "Unstiffened Elements Under Compression"; and (e) Section 1.9.2, "Stiffened Elements Under Compression." The applicant clarified that the seismic analysis of the containment hatchway crane did not include any fatigue evaluation or fatigue analysis that was based on time-dependent assumptions.

The staff noted that the applicant's response to RAI 4.1-2b clarifies what type of analyses were performed in the CLB in analysis of the containment hatchway crane and clarifies that the analysis of this crane was used solely to demonstrate that a failure of the crane during a postulated seismic event would not cause damage to safety-related equipment that would be required to be operable during such a seismic event or during a postulated design basis accident. The staff noted that the response RAI 4.1-2b confirms that the applicant's CLB does not include a fatigue analysis for the containment hatchway crane, which otherwise would have been performed if the applicant had opted to analyze the containment hatchway crane to the fatigue analysis criteria in Appendix B of the AISC Standard. Based on the review, the staff finds that the applicant has provided an acceptable basis of demonstrating that the CLB does not include a fatigue TLAA for the containment hatchway crane because the staff has confirmed that the CLB did not evaluate the containment hatchway crane to the fatigue analysis criteria in Appendix B of the AISC Standard. RAI 4.1-2b is resolved.

<u>Absence of a TLAA on Flow-Induced Vibration Endurance Limit for Reactor Vessel Internals</u>. In LRA Table 4.1-2, the applicant identified that the CLB does not include any flow-induced vibration analysis for the RVI components that would need to be identified as a TLAA in the LRA. The applicant stated that the flow-induced vibration analyses for the RVI components are not based on time-dependent assumptions defined by the life of the plant and therefore do not conform to the definition of a TLAA in 10 CFR 54.3.

SRP-LR Table 4.1-3 identifies that the CLB may include plant-specific flow-induced vibration analyses for the RVI components that qualify as TLAAs for the applicant's LRA.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "absence of a TLAA" basis. The staff noted that UFSAR Chapter 3.9.2.3 describes the flow-induced vibration analyses (dynamic modal analyses) that were performed on the RVI components and that served as the analysis reference points for evaluating the results of specific flow-induced vibration pre-operational and start-up tests performed on the RVI components before initial plant power operations. Specifically, the staff noted that the UFSAR identifies that the results of dynamic vibration analyses from other US nuclear plants ("sister plants") are used as a bounding basis for evaluating the results of the dynamic preoperational and startup tests that were performed on the RVI components. The staff also noted that UFSAR Section 3A identifies that the applicant uses this type of basis for conforming to the NRC's recommended position in RG 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals during Preoperational and Initial Startup Testing."

However, the staff noted that the UFSAR did not fully define which "sister plant" reports or analyses were being relied upon to baseline the results of the preoperational and startup tests on the RVI components, or identify whether these sister plant reports or analyses included any analyses of time-dependent vibration parameters that would need to be identified as TLAAs for the LRA. Therefore, by letter dated June 5, 2012, the staff issued RAI 4.1-3, requesting additional information on the following issues related to these flow-induced vibration analyses: (a) identification of all “sister plant” vibration reports, calculations, or evaluations, and the analyses in these documents, which were being relied upon for conformance with the NRC’s recommended position in RG 1.20; and (b) justification on why the vibration analyses in the “sister plant” reports, calculations, or evaluations would not need to be identified as applicable TLAAs when compared to the six criteria for defining TLAAs.

The applicant responded to RAI 4.1-3, parts (a) and (b) by letter dated July 3, 2012. In its response, the applicant stated that UFSAR Section 3A discusses the comprehensive vibration assessment program for the reactor internals during preoperational and initial startup testing, which was developed consistent with the NRC’s recommended regulatory position in RG 1.20. The applicant also stated that UFSAR Section 15D.9 identifies that it is defined by the General Electric Company as a fully instrumented prototype BWR-6 251 plant in accordance with RG 1.20, and that three-phase vibration testing of the reactor internals was performed at the applicant’s site as described in UFSAR Section 3.9.2.4. The applicant stated that “sister plant” flow-induced vibration assessments were not relied upon as part of the design basis. Based on this assessment, the applicant clarified that the CLB does not include any “sister plant” RVI flow-induced vibration analyses that need to be identified as TLAAs for the LRA.

The staff reviewed the UFSAR Section 15D for relevant information. Based on this review, the staff noted that the applicant’s response to RAI 4.1-3, parts (a) and (b) resolved the matter on whether the applicant’s RG 1.20 conformance basis for assessing RVI flow-induced vibrations was being done in comparison to RVI flow-induced vibration analyses for other BWR facilities (i.e., referred to “sister plants” in RAI 4.1-3) in the United States because the UFSAR confirms that the CLB does not include any “sister plant’ flow-induced vibration analyses that would need to be identified as TLAAs for the LRA. Therefore, the staff concern in RAI 4.1-3 is resolved.

However, the staff also noted that, in UFSAR Section 15D.8, the applicant does identify that GE performed a generic acoustic and flow-induced load analysis for the RVI components. The staff noted that, although this flow-induced vibration analysis does include a time dependency, the analysis assessed flow-induced vibrations of the internals only for the period associated with the initial operating cycle. Thus, the staff confirmed that, although the GE flow-induced vibration analysis is time-dependent, it is not based on (i.e., defined by) the life of the plant because the assessment only involves an assessment of vibrations over a single operating cycle and not through an assumed 40-year licensed life. Based on this review, the staff concludes that the applicant has provided a valid basis for concluding that the LRA does not need to identify any RVI flow-induced vibration TLAAs because the staff has confirmed that: (a) the GE flow-induced vibration analysis being relied upon in the applicant’s CLB is not a time-dependent analysis that is defined by the life of the plant, and (b) therefore, the analysis does not conform to Criterion 3 for defining TLAAs in 10 CFR 54.3(a).

Absence of a TLAA on Leak-Before-Break. In LRA Table 4.1-2, the applicant identified that its CLB review did not identify any time-dependent leak-before-break (LBB) analysis for the RCPB piping. The applicant stated that its CLB does not credit LBB as a safety analysis for the RCPB.

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 for the applicant’s LRA. The SRP-LR recommendations are only applicable to LBB analyses that were requested and approved by the staff to meet dynamic effect analysis relaxation requirements in 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 4, “Dynamic Effects.”

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 UFSAR information 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. Therefore, the staff concludes that the LRA does not need to include a plant-specific LBB TLAA because the staff has confirmed that: (1) the applicant’s design basis does not include an LBB analysis; and (2) the TLAA referenced in SRP-LR Table 4.1-3 for LBB analyses is not applicable to the CLB [Criterion 6 of 10 CFR 54.3(a)].

During its review, the staff noted that the applicant addresses its basis for complying with GDC 4 as part of the applicant’s HELB analysis criteria, which is addressed in UFSAR Section 3.6. The staff also noted that the applicant has included the design basis fatigue analyses for these HELB locations as TLAAs for the LRA and has discussed these HELB TLAAs in LRA Section 4.7.2. The staff’s evaluation of the applicant’s disposition of the HELB TLAA is documented in SER Section 4.7.2.

Absence of a TLAA on Metal Corrosion Allowance. In LRA Table 4.1-2, the applicant identified that the CLB does 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 plant-specific metal components corrosion allowance analyses that qualify as TLAAs for the applicant’s LRA.

The staff reviewed the UFSAR information for relevancy to the applicant’s “absence of a TLAA” basis. The staff also noted that UFSAR Table 3.9-2g identifies that the calculation of the minimum wall thickness for nozzles on the main steam safety/relief valves included the establishment of a corrosion allowance of the components. The staff also noted that UFSAR Section 5.4.5 (UFSAR page 5.4-30) identifies that a corrosion allowance of 0.120-inches minimum was added to minimum wall thickness for the main steam isolation valves (MSIVs) to provide for 40 years of service, and that UFSAR Table 3.9-2h identifies that the calculation of the corrosion allowance for the MSIVs was performed in accordance with ASME Code Section III NB-3646 requirements. The staff also noted that UFSAR Section 5.2.3.2.3, 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 UFSAR Section 6.1.1.1.2 makes an equivalent type of statement for those carbon steel components in the emergency safety feature systems that are exposed to a treated water environment. The staff noted that the UFSAR did not indicate that the additional metal, which was included in the pipe design by these corrosion allowances, was included in the pipe design as a result of any time-dependent analysis. Instead, the staff confirmed that the applicant included the additional corrosion allowances based on conformance with applicable non-time dependent code provisions in the ASME Section III Code of record for the facility and not on any analysis that is required to be a TLAA for the facility.

Therefore, based on this assessment, the staff concludes that the applicant provided an acceptable basis for concluding that the CLB does not include any corrosion allowance TLAAs because the staff has confirmed that additional metal corrosion allowances that were included in the plant's piping design were not based on any time-dependent analyses in the CLB.

Absence of a TLAA on Inservice Flaw Growth Analyses That Demonstrate Structure Stability for 40 Years. In LRA Table 4.1-2, the applicant identified that its CLB does not include any time-dependent inservice 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 plant-specific (from inservice inspection (ISI) findings) fatigue flaw growth or time-dependent flaw tolerance analyses that qualify as TLAAs for the ASME Code Class components that are within the scope of an applicant's LRA. SRP-LR Section 4.3.2.1.5 provides the staff's recommended plant-specific criteria for accepting these types of TLAAs in accordance with the TLAA acceptance requirements in 10 CFR 54.21(c)(1)(i), (ii), or (iii).

During the NRC aging management program (AMP) audit, held during the week of January 23, 2012, the staff confirmed that the CLB did not include any ISI-based flaw evaluations defined by a 40-year licensing period, with the exception of the applicant's cycle-dependent fracture mechanics evaluation for the feedwater (FW) nozzles to the plant's RV. The staff noted that the applicant used this analysis as part of its basis for managing cracking and for performing augmented ISI of the FW nozzles. The applicant credits its BWR Feedwater Nozzle Program (LRA AMP B.1.7) as the basis for managing cracking in these components. During the AMP audit, the staff confirmed that this AMP is based on and is consistent with the program element criteria in GALL Report AMP XI.M5, "BWR Feedwater Nozzles," and with the augmented inspection recommendations in GE Report No. GENE-523-A71-0594, Revision 1, and in NUREG-0619.

The staff noted that GENE-523-A71-0594, Revision 1, included a generic flaw tolerance evaluation of BWR FW nozzles to support the augmented ISI method and interval that GE recommends for the BWR nozzle designs, including the FW nozzles. The staff also noted that the generic analysis did state that the analysis was based on a 40-year design life for the facility. Therefore, the staff determined that the applicant would need to provide additional justification on why the plant-specific analysis, as applied to the evaluation of the FW nozzles, would not need to be identified as a TLAA for LRA. Therefore, by letter dated June 5, 2012, the staff issued RAI 4.1-4, requesting, in part (a), that the applicant clarify how this plant-specific fracture mechanics evaluation compares to the six criteria for defining TLAAs in 10 CFR 54.3(a). In RAI 4.1-4, part (b), the staff asked the applicant to provide further justification on why the fracture mechanics evaluation would not need to be identified as a TLAA in the LRA, as required by 10 CFR 54.21(c)(1).

The applicant responded to RAI 4.1-4 by letter dated July 3, 2012. In its response to RAI 4.1-4, part (a), the applicant clarified that its plant-specific flaw tolerance analysis used to support the ISI interval for the FW nozzle in GENE-523-A71-0594, Revision 1, conformed to all six of the criteria for defining TLAAs in 10 CFR 54.3(a), except for Criterion 3. The applicant stated that this analysis did not conform to Criterion 3 in 10 CFR 54.3(a) because it does not include a time dependency and, therefore, is not a time-dependent analysis defined by the life of the plant. In its response to RAI 4.1-4, part (b), the applicant stated that the intent of the plant-specific fracture mechanics evaluation was to justify the inspection intervals in the GE generic evaluation. The applicant stated that the specific evaluation concluded that the results presented therein were valid for use in establishing future FW nozzle reinspection intervals based on the alternate requirements specified in the generic evaluation; therefore, the specific evaluation did not qualify the FW nozzles for a fixed term and is not a TLAA.

The staff noted that the applicant is using the frequency for performance of the alternative FW nozzle inspections to define the time period associated with the flaw tolerance analysis that is described and evaluated in the applicant's plant-specific flaw tolerance analysis for the FW nozzle. In contrast, the staff noted that the inspection interval for the alternative FW nozzle ultrasonic examinations is part of the safety basis for the nozzles because it is part of the basis for establishing acceptable alternative inservice requirements for the nozzle under the requirements of 10 CFR 50.55a. The ISI interval does not establish the time frame assumed for the flaw tolerance analysis in the GE report because it is actually part of the applicant's safety basis decision, not the analysis basis supporting that decision. Thus, the staff concluded that the applicant should have identified the plant-specific flaw tolerance analysis for the FW nozzle as a TLAA in the LRA because it meets all six of the criteria for TLAAs in 10 CFR 54.3(a). This includes conformance with TLAA identification Criterion 3 in that the evaluation is based on time-dependent assumptions defined by the life of the plant.

By letter dated September 7, 2012, the staff issued follow-up RAI 4.1-4a, requesting, in part (a), further justification on why the applicant had not identified the plant-specific flaw tolerance analysis for the FW nozzle as a TLAA in the LRA. The applicant provided its response to RAI 4.1-4a in a letter dated October, 2, 2012. In its response, the applicant stated that the flaw tolerance evaluation for the feedwater nozzle was performed to establish the adequacy of the periodic inspection interval. The applicant stated that the analysis evaluated a postulated flaw in the feedwater nozzle and demonstrated that, based on the transient loadings for the assumed flaw in the analysis, the feedwater nozzles would be acceptable for 19.5 years. The applicant clarified that the 19.5 years was an output of the analysis that was used to support the establishment of a 10-year inspection interval for the feedwater nozzle. The applicant used this basis to make a conclusion that the analysis does not involve time-limited assumptions defined by the current operating term. The applicant further stated that the analysis was not performed for the purpose of qualifying the RPV feedwater nozzle to the expiration of the current operating term, and thus did not need to be identified as a TLAA.

The staff noted that it is the input to the flaw tolerance analysis that would establish whether the analysis is based on time-dependent assumptions defined by the current operating term for the facility. Thus, the staff noted that the applicant's basis would be valid if the analysis used the number of design basis transients occurring over a 19.5-year period as the assumed inputs for the flaw growth (flaw tolerance) analysis. However, the staff noted that this basis would not be valid if the analysis used the number of transients occurring over a 40-year licensing basis period as the inputs for the flaw growth analysis. Thus, the staff needed additional information regarding the input to the flaw tolerance analysis to verify whether the analysis was based on time-limited assumptions defined by the current operating period for the facility.

By letter dated November 5, 2012, the staff issued RAI 4.1-4b, the staff asked the applicant either to provide the plant-specific flaw tolerance analysis discussed in the response to RAI 4.1-4a or justify that the analysis did not involve the use of any time-limited assumptions defined by the current operating term as input.

The applicant responded to RAI 4.1-4b by letter dated November 29, 2012. In its response, the applicant clarified that the referenced, plant-specific flaw tolerance evaluation for the RV feedwater nozzles was based on an evaluation of applicable plant transient cycle occurrences over an approximately 5-year period from 1990 to 1995. The applicant stated that for each transient assumed in the analysis, the cycle count as of September 30, 1990, was subtracted from the cycle count as of April 15, 1995. The applicant explained that the results were divided by 4.5 years to obtain the occurrences of each transient per year over that time period and that the annual occurrence rates were used as input into the flaw tolerance evaluation to determine the number of years that it would take for a postulated flaw to grow to the critical flaw size. The applicant stated that the evaluation demonstrates that the flaw in the FW nozzle would be acceptable over a 19.5-year period.

The staff reviewed the response to RAI 4.1-4b and noted that the response clarifies how the assessment of design basis transients was performed as part of the flaw evaluation for the FW nozzle. The staff noted that the response demonstrates that the assessment of design transients in the flaw evaluation was based only on a 5-year time period and was not based on time-dependent assumptions defined by the current operating period. Instead, the analysis demonstrates that the 10-year interval for the FW nozzle is an acceptable frequency for inspections of the component. Therefore, the staff's concerns described in RAIs 4.1-4, 4.1-4a, and 4.1-4b are resolved.

Thus, the staff concludes that the applicant has provided an acceptable basis for concluding that the flaw evaluation for the FW nozzle does not need to be identified a TLAA because (a) the staff has confirmed that flaw evaluation does not involve time-dependent assumptions defined by the current operating term, and (b) this demonstrates that the analysis does not conform to criterion No. 3 of the definition of TLAA, as stated in 10 CFR 54.3(a).

<u>Potentially Applicable TLAAs in Response to BWRVIP Report Applicant Action Items</u>. The staff noted that inclusion of LRA AMP B.1.11, "BWR Vessel Internals," confirms that the applicant applies the Boiling Water Reactor Vessel and Internals Project (BWRVIP) inspection and flaw evaluation (I&FE) guideline reports as part of its basis for managing the aging effects applicable to the RVI components. Therefore, the staff noted that the NRC-issued SEs on the BWRVIP reports referenced in GALL Report AMP XI.M9, "BWR Vessel Internals," and other BWRVIP I&FE guidelines referenced in the applicant's LRA (specifically BWRVIP-18-A, BWRVIP-25, BWRVIP-26-A, BWRVIP-27-A, BWRVIP-38, BWRVIP-41, BWRVIP-42-A, BWRVIP-47-A, BWRVIP-48-A, BWRVIP-49-A, BWRVIP-74-A, and BWRVIP-76-A) include applicant action items (AAIs) that relate to the identification of TLAAs.

The staff verified that the applicant included its responses to the AAIs on these BWRVIP reports in Appendix C of the LRA. The staff's evaluations of the applicant's responses to these AAIs are given below.

AAIs that are Common to BWRVIP Report Nos. BWRVIP-18-A, BWRVIP-25, BWRVIP-26-A, BWRVIP-27-A, BWRVIP-38, BWRVIP-42-A, BWRVIP-47-A, BWRVIP-48-A, BWRVIP-49-A, BWRVIP-74, and BWRVIP-76

The staff verified that the applicant's AAI response bases included the applicant's response bases to the three AAIs that are common to all of these BWRVIP reports:

- AAI No. 1, which relates to the AMPs that are credited for aging management of the applicant's RPV and RVI components, as required by 10 CFR 54.21(a)(3), and the need to commit to AMPs that incorporate and will implement the protocols in the BWRVIP I&FE guideline documents.

- AAI No. 2, which relates to the requirement in 10 CFR 54.21(d) and the generic need for inclusion of a final safety analysis report (FSAR) supplement for each AMP and TLAA that is credited for aging management of the applicant's RPV and RVI components.
- AAI No. 3, which relates to the requirement in 10 CFR 54.22 and the generic need to identify any TS requirements that relate to aging management or evaluation of the applicant's RPV or RVI components and would need to be amended in the LRA.

In its response to AAI No. 1, the applicant stated that the design of the GGNS has been verified to be bounded by the referenced BWRVIP reports. The applicant also stated that it commits to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. The applicant further stated that the applicable commitments are administratively controlled in accordance with the requirements of the applicant's 10 CFR Part 50, Appendix B, quality assurance program and that any deviation from a BWRVIP report approved by the NRC will be reported to the NRC in accordance with the protocols of Technical Report BWRVIP-94.

The staff noted that the referenced BWRVIP reports have been incorporated by reference in the following AMPs for the LRA: (a) LRA AMP B.1.8, "BWR Penetrations," which incorporates BWRVIP-27-A and BWRVIP-49-A; (b) LRA AMP B.1.10, "BWR Vessel ID Attachment Welds," which incorporates BWRVIP-48-A; and (c) LRA AMP B.1.11, "BWR Vessel Internals," which incorporates the remaining BWRVIP reports described in the following sections. The staff also verified that the applicant's need to implement these programs and BWRVIP I&FE guidelines are already within the scope of plant-specific commitments in the CLB for implementing the Electric Power Research Institute (EPRI) BWRVIPs that have been issued and approved by the staff, and that the applicant is already implementing these BWRVIP protocols in accordance with its existing NEI 03-08 and BWRVIP-94 implementation commitments. The staff also noted that this basis is appropriately reflected in the applicant's response to AAI No. 1. Based on this review, the staff finds that the applicant has appropriately resolved the request in AAI No. 1 because the applicant has protocols in place to implement the applicable BWRVIP reports, and has implemented these BWRVIP protocols in accordance with the applicant's "Existing" AMPs. The staff evaluations of these programs are provided in appropriate sections of this SER (e.g., SER Section 3.0.3.1.9 for the BWR Vessel ID Attachment Welds Program, SER Section 3.0.3.1.7 for the BWR Penetration Program, and SER Section 3.0.3.1.10 for the BWR Vessel Internals Program). The request in AAI No. 1 is resolved.

In its response to AAI No. 2, the applicant stated that the UFSAR supplement is included as LRA Appendix A and includes a summary of the programs and activities specified as necessary for those BWRVIP programmatic activities. The staff verified that the applicant has appropriately included the applicable UFSAR supplement summary descriptions for those programmatic BWRVIP activities that are within the scope of the applicant's BWRVIP-based AMPs and TLAAs in the following sections of the LRA: (a) Section A.1.8 for the BWR Vessel ID Attachment Welds Program; (b) Section A.1.10 for the BWR Penetrations Program; (c) Section A.1.1 for the BWR Vessel Internals Program; (d) Section A.2.2.1 for the metal fatigue TLAAs for RPV and RVI components; (e) Section A.2.1 for the RPV neutron embrittlement TLAAs; and (f) Section A.2.5.3 for the TLAA related to neutron fluence effects for the RVI components.

Based on this review, the staff finds that the applicant has resolved the request in AAI No. 2 because the staff has confirmed that the applicant has provided the appropriate UFSAR supplements for the RPV and RVI-related AMPs and TLAAs in Appendix A of the LRA. The staff evaluations of these UFSAR supplements are provided in appropriate sections of this SER (e.g., SER Section 3.0.3.1.9 for the BWR Vessel ID Attachment Welds Program, SER Section 3.0.3.1.7 for the BWR Penetration Program, SER Section 3.0.3.1.10 for the BWR Vessel Internals Program, SER Section 4.2 for the RPV neutron embrittlement TLAAs, SER Section 4.3 for the RPV and RVI metal fatigue TLAAs, and SER Section 4.7.3 for the TLAA related to neutron fluence effects for the RVI components). The request in AAI No. 2 is resolved.

In its response to AAI No. 3, the applicant stated that it did not identify any TS changes that would need to be identified for the LRA based on BWRVIP I&FE guidelines. The staff noted that the only potentially relevant TS requirements are those for the P-T limits TLAA. As described in SER Section 4.2.2, the staff evaluated and found acceptable the applicant's intent to manage the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii), including deferral of a submittal with updated P-T limit curves until such time as the applicant would be required to submit them in accordance with the requirements of 10 CFR Part 50, Appendix G, and its 10 CFR 50.90 LAR process. The request in AAI No. 3 is resolved.

AAI No. 4 on BWRVIP-18-A (BWRVIP I&E Guidelines for Internal BWR Core Spray Lines)

The staff noted that AAI No. 4 for BWRVIP-18-A, states that BWR applicants for renewal should identify all TLAAs applicable to the design of its core spray (CS) internal components. In its response to this AAI, the applicant stated that the fatigue analysis for the internal portions of the CS line and CS sparger was the only analysis for these components that conformed to the definition of a TLAA. The staff confirmed that the applicant includes its fatigue analysis TLAA for these components in LRA Section 4.3.1.3 and includes the CUF value for these components in LRA Table 4.3-3. The staff also confirmed that the fatigue analysis for the internal portions of the CS line and sparger was the only analysis that conformed to the definition of a TLAA in 10 CFR 54.3(a). Based on this review, the staff finds the applicant's response to this AAI to be acceptable because it has confirmed that the applicant has included the applicable fatigue TLAA for the components in the LRA and that the design basis does not include any other analysis that needs to be identified as a TLAA for these components. The staff evaluates the applicant's disposition for the metal fatigue TLAA for the internal portions of the CS line and the CS sparger in SER Section 4.3.1.3.2. AAI No. 4 on BWRVIP-18-A is resolved.

AAI No. 4 on BWRVIP-25 (BWRVIP I&E Guidelines for BWR Core Plates)

The staff noted that AAI No. 4 for BWRVIP-25, states that BWR applicants for license renewal should identify and evaluate whether the evaluation of stress relaxation of in-core plate rim holddown bolts should be identified as a TLAA for the components. In its response to this AAI, the applicant stated that the structural integrity of the core plate is ensured by the inclusion of wedges that hold the core plate in place and that the design does not rely on rim holddown bolts that are tensioned (preloaded) in place. Based on this design feature, the applicant stated that the design of the core plate does not include any analysis with regard to preloading of rim holddown bolts that would need to be identified as a TLAA in the LRA. The staff confirmed that UFSAR Section 4.5.2.1 states that the core plate design includes wedges for structural integrity. The staff confirmed that these wedges are relied upon as the basis for maintaining structural integrity of the core plate against lateral movement instead of reliance on core plate rim hold-down bolts. Based on this review, the staff finds the applicant's response to this AAI to be acceptable because it has confirmed that the structural integrity of the core plate does not rely on the tensioned rim holddown bolts and that the CLB does not include any analysis of preloaded core plate rim holddown bolts. AAI No. 4 on BWRVIP-25 is resolved.

AAI No. 4 on BWRVIP-26-A (BWRVIP I&E Guidelines for BWR Top Guide Assemblies)

The staff noted that AAI No. 4 for BWRVIP-26-A, states that BWR applicants for license renewal should identify and evaluate the projected accumulated neutron fluence for BWR top guides that need to be identified as a TLAA for the assessment of irradiated-assisted stress-corrosion cracking (IASCC) in the components. In its response to this AAI, the applicant stated that the 60-year projected fluence value for the top guide exceeds the threshold for the initiation of IASCC-induced cracking in the top guide and its subcomponents. However, the applicant stated that methodology in BWRVIP-26-A does not include any analysis that would constitute a TLAA since the report was not used to make any safety determination or as justification for reducing the number of inspections that would be applied to these components. The applicant stated that since it has implemented the inspection requirements of BWRVIP-26-A and BWRVIP-183, its program will be adequate to manage the effects of aging on the top guide assembly for the period of extended operation. The staff confirmed that the referenced BWRVIP-26-A report does not rely on any generic TLAA for evaluating IASCC-induced cracking in the applicant's top guide design or its subcomponents. The staff also confirmed that the CLB did not include any specific analysis for the top guide that conformed to the six criteria for TLAAs in 10 CFR 54.3(a) or that would need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1). Instead, the staff noted that the applicant relies on inspections of the top guide that will be conducted using AMP B.1.11, "BWR Vessel Internals" Program, and the methodology of BWR-26-A as the basis for inspecting cracking in the tope guide and its subcomponents. The staff evaluates the applicant's BWR Vessel Internals Program in SER Section 3.0.3.1.11. AAI No. 4 on BWRVIP-26-A is resolved.

AAI No. 4 on BWRVIP-27-A (BWRVIP I&E Guidelines for Standby Liquid Control Nozzles)

The staff noted that AAI No. 4 for BWRVIP-27-A, states that BWR applicants for license renewal referencing the BWRVIP-27-A report should identify and evaluate whether the CLB includes any projected fatigue CUF analyses that would need to be identified as potential TLAAs for their standby liquid control (SLC)/core ΔP line nozzles. In its response to this AAI, the applicant stated that the fatigue analysis of the SLC/core ΔP line for 60 years of operation is a potential TLAA in the LRA. However, the applicant stated that the NRC SE for BWRVIP-27 recognizes that this fatigue analysis is not required for all SLC/core ΔP configurations. The applicant stated that the CS system provides the flow path for injection of boron from the SLC system; therefore, the ΔP/SLC lines inside the RPV do not have a license renewal intended function and are not subject to an AMR. Thus, based on this assessment, the applicant stated that its CLB does not include any TLAAs associated with the inspection and evaluation guidelines in BWRVIP-27-A.

The staff noted that UFSAR drawing M-1086 identifies that the borated water flow path from the SLC system does not inject directly into the RPV using an SLC/core ΔP nozzle. Instead, the staff confirmed that the SLC system injects into the RCPB through a branch connection to the RCPB portion of the high-pressure core spray (HPCS) system. The staff confirmed that the UFSAR drawing indicates this SLC branch connection is located directly downstream of check valve F005 and upstream of block valve F036 in the HPCS system. The staff also confirmed that the applicant has included its TLAA for the fatigue analysis of the Class 1 portion of the SLC system in LRA Section 4.3.1.6 and CUF value for the limiting SLC piping component in LRA Table 4.3-5. Based on this confirmation, the staff finds the applicant's response to AAI No. 4 acceptable because the staff has confirmed that: (1) the CLB does not include any fatigue analysis for a SLC/core ΔP RPV nozzle that would need to be identified as a TLAA in the LRA, and (2) the applicant has included its analogous fatigue usage value for the SLC system in

LRA Section 4.3.1.6 and the limiting CUF value for the SLC system in LRA Table 4.3-5. AAI No. 4 on BWRVIP-27-A is resolved.

AAI No. 4 on BWRVIP-42-A (I&E Guidelines for LPCI Coupling Components)

The staff noted that AAI No. 4 for BWRVIP-42-A, states that BWR applicants for license renewal referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues that may affect the structural integrity of its RPV internal low-pressure coolant injection (LPCI) coupling components. In its response to this AAI, the applicant stated that the potential TLAA issues for LPCI components have been evaluated in LRA Section 4.3.1.3.

The staff noted that UFSAR drawing M-1087 confirms that, when called upon, the design provides emergency low-pressure system inventory into the RPV during a postulated design basis accident (DBA) event using a low-pressure core spray (LPCS) system. LPCS is the system that is analogous to the LPCI systems used to achieve identical emergency core cooling objectives for earlier GE Model 4 BWR designs. The staff confirmed that LRA Section 4.3.1.3 includes a fatigue TLAA for the vessel head cooling spray nozzle and LRA Table 4.3-3 included the CUF value for this component. The staff also confirmed that the applicant included its fatigue analysis TLAA for portions of the LPCS system external to the RPV in LRA Section 4.3.1.6 and the limiting CUF for the LPCS piping in LRA Table 4.3-5. Thus, the staff noted that the LRA did include appropriate CUF values for portions of the LPCS system that are both internal and external to the RPV. Based on this review, the staff finds the applicant's response to this AAI is acceptable because the staff has confirmed that the applicant has included an appropriate TLAA for the LPCS spray nozzle in LRA Section 4.3.1.3. The staff evaluates the applicant's disposition for the metal fatigue TLAA for the LPCS spray nozzle in SER Section 4.3.1.3.2. AAI No. 4 on BWRVIP-42-A is resolved.

AAI No. 4 on BWRVIP-47-A (I&E Guidelines for BWR Lower Plenum Components)

The staff noted that AAI No. 4 for BWRVIP-47-A, states that BWR applicants referencing the BWRVIP-47-A report for license renewal should identify and evaluate any projected CUFs in the CLB for their lower plenum area components as potential TLAAs for the LRA. In its response to this AAI, the applicant stated that the potential TLAA issues for RPV internal lower plenum components have been evaluated and included in LRA Section 4.3.1.3.

The staff confirmed that the applicant assessed its metal fatigue TLAA for the RPV internal lower plenum area components in LRA Section 4.3.1.3 and noted that Table 4.3-3 in this LRA section includes appropriate CUF values for the following RPV internal lower plenum area components: (a) internal control rod drive (CRD) housings, (b) internal in-core housings and guide tubes, and (c) access hole covers. Based on this review, the staff finds the applicant's response to this AAI is acceptable because the staff has confirmed that the applicant has included appropriate CUF values for these RPV internal lower plenum area components in LRA Section 4.3.1.3. The staff evaluates the applicant's disposition for the metal fatigue TLAA for these lower plenum area components in SER Section 4.3.1.3.2. AAI No. 4 on BWRVIP-47-A is resolved.

AAIs on BWRVIP-74-A (Reactor Vessel Inspection and Flaw Evaluation Guidelines for License Renewal)

The staff noted that the NRC SE on the BWRVIP-74-A included the following TLAA-related AAIs:

- AAI No. 8 on identification of appropriate metal fatigue TLAAs for the RPV components
- AAI No. 9 on identification of appropriate P-T limit analysis TLAAs for the RPV beltline components in the LRA
- AAI No. 10 on identification of appropriate USE analysis TLAAs for the RPV beltline components in the LRA
- AAI Nos. 11 and 12 on identification of appropriate TLAAs related to appropriate time-dependent probability of failure analyses for RPV axial and circumferential welds used to support ISI relief requests requested on relief from applicable RPV circumferential weld examination requirements
- AAI No. 13 on providing 60-year neutron fluence values for those TLAAs that have been included in the LRA for neutron irradiation embrittlement (i.e., P-T limit, USE, and the RPV axial and circumferential weld probability of failure analyses)
- AAI No. 14 on providing applicable time-dependent flaw tolerance or flaw growth analysis for ASME Code Class 1 RPV components

The staff confirmed that the applicant responded to these AAIs by referencing the appropriate subsections in LRA Section 4 that relate to the TLAA topics. The staff has evaluated the applicant's bases for including the TLAAs referenced in its responses to AAI Nos. 8 through 13 in SER Section 4.1.2.1.1. The staff has evaluated the applicant's basis for omitting identification of a fatigue flaw growth TLAA for the FW nozzle in SER Section 4.1.2.1.2. AAI Nos. 8 through 14 on BWRVIP-74-A are resolved.

<u>Impact of Extended Power Uprate License Amendment Request on TLAAs Identified for the LRA</u>. The staff noted that LRA Section 1.2 indicates that the applicant submitted a 10 CFR 50.90 LAR for approval of an extended power uprate (EPU). The EPU amendment was subsequently issued on July 18, 2012. The licensed thermal power level increased to 4408 MWt as a result of the EPU approval. The applicant stated that changes to the operating parameters because of the increase in power were considered during the LRA preparation. The applicant stated that a specific example of the impact that the EPU would have on the TLAAs for the LRA is the higher neutron fluence values that would result from the EPU. These neutron fluence values are used in the applicant's evaluation of TLAAs on neutron irradiation embrittlement, as discussed and evaluated in LRA Section 4.2. The applicant also stated that any small changes in operating parameters as a result of the EPU would have little effect on aging effects requiring management.

The staff noted that 10 CFR Part 54 requires that all calculations and analyses that meet the six criteria in 10 CFR 54.3(a) to be identified as a TLAA in the LRA. One of these criteria is that the calculation or analysis must be contained or incorporated by reference in the CLB for it to be defined as a TLAA. Thus, the staff observed that the EPU might not be approved by the time the staff had completed its LRA review. Therefore, the staff noted that the TLAAs in the LRA that referenced post-EPU operating conditions and parameters might not be based on conservative assumptions because the EPU had not yet been approved for the applicant's CLB. Therefore, by letter dated June 5, 2012, the staff issued RAI 4.1-6, asking the applicant to identify all the TLAAs discussed in the LRA Section 4 that have used post-EPU operating conditions and parameters in their calculations and analyses.

In its response dated July 3, 2012, the applicant stated that each of the following analyses in LRA Section 4 considered the post-EPU operating conditions and parameters: RV neutron embrittlement evaluations in LRA Section 4.2 include consideration of increased EPU fluence;

fatigue analysis results in LRA Section 4.3 include re-evaluations to reflect EPU operating conditions; EQ evaluations in LRA Section 4.4 included EPU conditions; the containment liner plate, metal containments and containment penetrations evaluations for LRA Section 4.6 included considerations of EPU conditions; and each of the evaluations in LRA Section 4.7 for the erosion of the main steam line (MSL) flow restrictors, determination of intermediate HELB locations, and fluence effects on the RVI included considerations of EPU operating conditions. The staff noted that the applicant received its EPU license amendment on July 18, 2012, and the post-EPU operating conditions described in the LRA became the applicant's CLB.

The staff finds the applicant's response to RAI 4.1-6 acceptable because it identified all the analyses discussed in the LRA Section 4 that have utilized post-EPU operating conditions and parameters. Furthermore, the issue described in RAI 4.1-6 is resolved because the post-EPU operating conditions described in the LRA became the applicant's CLB with the approval of the EPU license amendment dated July 18, 2012. Thus, the calculations, evaluations, or analyses, identified in LRA Section 4, meet all six criteria in 10 CFR 54.3(a) in order for them to be defined as a TLAA.

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 and in effect that are based on a TLAA, evaluate them, and justify their use during the period of extended operation. The LRA states that each active exemption was reviewed to determine whether it was based on a TLAA. The staff also reviewed the applicant's CLB to see if the CLB included any exemptions granted in accordance with 10 CFR 50.12 and based on a TLAA. The staff's review included the current operation license, the TS, and UFSAR for the facility. The staff's review also included a search of the NRC's main and legacy libraries in the NRC's Agencywide Documents and Access Management System (ADAMS) Document Control Library using the keyword "exemption."

The staff noted that the P-T limits for the RV and RCPB were based on full compliance with the P-T limit generation requirements in 10 CFR Part 50, Appendix G, and Appendix G of the ASME Code Section XI. The staff also noted that the 32 effective full-power years (EFPYs) P-T limits were granted in the NRC's SE associated with License Amendment No. 132, which was issued on August 27, 1997. Thus, the staff confirmed that the applicant's generation of the 32 EFPY P-T limits for the facility was not based on any exemption from the requirements for generating P-T limits in 10 CFR Part 50, Appendix G, or in Appendix G of the ASME Code Section XI.

The staff also noted that Clause 2.D in the applicant's Operating License, NPF-29 identifies that the applicant was granted a number of exemptions from the requirements in 10 CFR Part 50, Appendix A; 10 CFR Part 50, Appendix J, and 10 CFR Part 100. The operating license states that the NRC found it acceptable to approve these exemptions based on compliance with one or more of the exemption acceptance criteria in 10 CFR 50.12. However, the staff noted that the operating license did not provide further discussion on the basis for these exemptions and whether approval of the exemptions was based all or in part on any analysis for the CLB that would need to be identified as a TLAA in the LRA. Therefore, by letter dated June 5, 2012, the staff issued RAI 4.1-5, requesting, in part (a), a summary of each of the exemptions that have been referenced in Clause 2.0 of Operating License, NPF-29, including the basis for requesting NRC approval of the exemption. In RAI 4.1-5, part (b), the staff asked the applicant to clarify whether the basis for requesting these exemptions, before their approvals, were based on analyses that would need to be identified as a TLAAs in accordance with 10 CFR 54.21(c)(1). In RAI 4.1-5, part (c), the staff asked the applicant to justify whether the exemptions referenced in Clause 2.0 of Operating License, NPF-29, need to be identified as exemptions that are based on a TLAA and that need to be identified in accordance with 10 CFR 54.21(c)(2).

In a teleconference call held with the applicant on May 15, 2012, the staff provided clarification to the applicant that in its response to RAI 4.1-5, it needed to address the exemption that was granted from applicable 10 CFR Part 50, Appendix J, containment leak rate testing requirements. The staff clarified that the applicant did not need to provide an explanation for the exemption granted from GDC 17 in 10 CFR Part 50, Appendix A, GDC Criteria, because the license indicated that the exemption only applied until the plant startup out of the first refueling outage, for: (1) the emergency override of the test mode for the Division 3 diesel engine, (2) the second level of undervoltage protection for the Division 3 diesel engine, and (3) the generator ground over current trip function for the Division 1 and 2 diesel generators. Thus, the exemption from GDC 17 requirements, as mentioned in Operating License, NPF-29, is not applicable to the period of extended operation. The staff informed the applicant that it would not need to provide an explanation for the exemption granted from 10 CFR 100.11(a)(1) requirements because the operating license is clear that the exemption is only in regard to defining the activities that would need to be controlled in the plant exclusion areas, as defined in accordance with 10 CFR 100.3(a) exclusion area provision, and that this exemption was not based on any TLAA analysis applicable to the LRA.

The applicant responded to RAI 4.1-5 by letter dated July 3, 2012, relative to the exemption granted from 10 CFR Part 50, Appendix J, containment leak rate testing requirements. In its response to RAI 4.1-5, part (a), the applicant stated that the exemption, which involves an exemption for containment airlock testing, was granted for the term of the operating license as described in Supplemental SER No. 7, Section 6.2.6.

The applicant stated that the exemption from the 10 CFR Part 50, Appendix J, testing requirements is because of a requirement in paragraph III.D.2(b)(ii) of 10 CFR Part 50, Appendix J, that the applicant deemed to be a hardship for the plant. In its response to RAI 4.1-5, parts (b) and (c), the applicant clarified that the justification provided in support of this exemption did not rely on a time-limited analysis or assumption to support the exemption acceptance basis, and that based on this fact, the exemption does not need to be identified as an exemption that meets 10 CFR 54.21(c)(2) requirements.

Based on the explanation the applicant provided, the staff noted that the referenced exemption for the 10 CFR Part 50, Appendix J, containment leak rate testing requirements is only based on justification that an alternative containment leak rate test would provide an acceptable level of quality and safety in lieu of performing the full pressure test of the airlocks. The staff noted that the basis for the exemption does not rely upon any TLAA that has been included in the LRA. Thus, based on this review, the staff finds that the applicant has provided an acceptable basis that demonstrates that the exemption from 10 CFR Part 50, Appendix J, containment leak rate testing requirements in Operating License, NPF-29 do not need to be identified for the LRA in accordance with 10 CFR 54.21(c)(2) requirements because the exemption is not based on a TLAA. The staff concern in RAI 4.1-5 is resolved.

Based on this review, the staff concludes that the CLB does not include any exemptions that are based on a TLAA and that need to be identified for the LRA based on compliance with the requirement in 10 CFR 54.21(c)(2).

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an accurate list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff also concludes that the applicant has appropriately identified that it has no 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 Vessel Neutron Embrittlement

4.2.1 Reactor Vessel Fluence

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 describes the applicant's analysis for RV high-energy neutron fluence (unit of n/cm^2 with energies greater than 1 MeV), which involves a time-limited assumption defined by the operating term. Based on operating at an EPU power level beginning with Cycle 19, the predicted peak high-energy neutron fluence for 54 EFPY is 4.44×10^{18} n/cm^2 (E > 1 MeV) at the vessel inner surface. The neutron fluence for the welds and shells of the RV beltline region was determined using the General Electric-Hitachi (GEH) method for neutron flux calculation documented in report NEDC-32983P-A and approved by the NRC. This method adheres to the guidance provided in RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Results of the fluence evaluation are shown in LRA Table 4.2-1.

In the LRA, the applicant did not disposition the fluence analysis for the RV in accordance with 10 CFR 54.21(c)(1)(i), 54.21(c)(1)(ii), or 54.21(c)(1)(iii). The staff evaluated the applicant's fluence analysis and TLAA disposition as described below.

4.2.1.2 Staff Evaluation

The staff reviewed the applicant's fluence analysis for the RV consistent with SRP-LR Section 4.2, which indicates that the applicant identifies (a) the neutron fluence for the RV at the expiration of the license renewal period, (b) the staff-approved methodology used to determine the neutron fluence (or submits the methodology for staff review), and (c) whether the methodology follows the guidance in NRC RG 1.190.

LRA Section 4.2.1 addresses the applicant's RV fluence calculations. LRA Section 4.2.1 states that the fluence is calculated based on a time-limited assumption defined by the operating term, which indicates that the RV neutron fluence analysis is a TLAA. In contrast, LRA Table 4.1-1, "List of GGNS TLAAs and Resolution," does not identify the neutron fluence calculation as a TLAA. In addition, the LRA does not address the applicant's TLAA disposition of the neutron fluence analysis in terms of the dispositions described in 10 CFR 54.21(c)(1)(i), (ii) or (iii).

By letter dated June 27, 2012, the staff issued RAI 4.2.1-1 requesting that the applicant clarify why LRA Table 4.1-1 does not identify the neutron fluence calculation as a TLAA. The staff also requested, in Part (b), that, if the fluence calculation is identified as a TLAA, the applicant describe the TLAA disposition of the neutron fluence calculation in terms of the dispositions described in 10 CFR 54.21(c)(1)(i), (ii), or (iii). In addition, the staff requested, in Part (b), that the applicant revise LRA Section 4.2.1, Table 4.1-1, and Section A.2.1.1 (UFSAR supplement for RV fluence) to include a relevant TLAA disposition, consistent with the response.

In its response dated July 25, 2012, the applicant stated in response to RAI 4.2.1-1, Part (a), that the neutron fluence calculation is not a TLAA since, as a stand-alone analysis, it does not meet the definition in 10 CFR 54.3(a). The applicant also stated that specifically, a neutron fluence calculation does not “consider the effects of aging,” which is the second element of the six-element definition of a TLAA in 10 CFR 54.3(a). In addition, the applicant stated, in response to RAI 4.2.1-1, Part (b), that, although the neutron fluence calculation does not meet the 10 CFR 54.3(a) definition of a TLAA, the calculation is projected to the end of the period of extended operation for use in demonstrating that neutron embrittlement analyses have been projected to the end of the period of extended operation. The applicant further stated that the validity of the neutron embrittlement TLAAs is based on a valid input of neutron fluence at the end of the period of extended operation.

In its review, the staff noted that, since the RV neutron fluence analysis considers the accrual of neutrons on the RV surface as a function of the reactor operating power level and operating time, the neutron fluence analysis considers the effects of aging (i.e., neutron embrittlement of the RV). The RV neutron fluence analysis with a time-limited assumption is also integral to the neutron embrittlement TLAAs for the RV (e.g., USE analysis and P-T limits analysis). Therefore, the staff noted that the RV neutron fluence analysis should be identified as a TLAA with an adequate TLAA disposition, as addressed in 10 CFR 54.21(c)(1)(i), (ii) or (iii). By letter dated September 14, 2012, the staff issued RAI 4.2.1-1a, Part (a), requesting that the applicant identify the RV neutron fluence analysis as a TLAA, based on the fact that the neutron fluence analysis considers the accrual of neutrons on the vessel surface as a function of the reactor operating power level and is integral to the neutron embrittlement TLAAs for the RV, or provide justification for why the analysis is not a TLAA. RAI 4.2.1-1a, Part (b), requested that the applicant describe its disposition of the neutron fluence TLAA and revise appropriate LRA sections as necessary.

The applicant responded to RAI 4.2.1-1a in its letter dated October 15, 2012. In its response, the applicant stated in response to RAI 4.2.1-1a, Part (a), that the effects of aging due to neutron fluence are considered in the neutron embrittlement TLAAs (e.g., USE analysis and P-T limits analysis). The applicant also stated that in response to RAI 4.2.1-1a, the RV neutron fluence analysis shall be treated as a TLAA. In addition, the applicant's response to RAI 4.2.1-1a, Part (b), dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(ii), which indicates that the neutron fluence TLAA has been projected to the end of the period of extended operation. In its response, the applicant also revised LRA Section 4.2.1, Table 4.1-1, and Section A.2.1.1 (UFSAR supplement) to appropriately reflect the TLAA disposition, consistent with its response. In its review, the staff finds this portion of the applicant’s response to RAI 4.2.1-1a acceptable, because the applicant identified the RV neutron fluence calculations as a TLAA with a relevant disposition and revised the LRA, consistent with its response to RAI 4.2.1-1a. Based on this review, the staff finds the issues related to RAIs 4.2.1-1 and 4.2.1-1a resolved. The staff’s review related to the applicant’s TLAA is further described below.

LRA Section 4.2.1 addresses the peak neutron fluence values (energy greater than 1 MeV) for 54 EFPYs based on planned EPU power level beginning with Cycle 19. The predicted peak neutron fluence value is 4.44×10^{18} n/cm^2 at the vessel inner surface of the lower-intermediate shell and axial welds (i.e., Shell Plate 2 location). The LRA also states that the neutron fluence for the RV beltline region was determined using the GEH method for neutron flux calculation documented in report NEDC-32983P-A and approved by the NRC. The LRA further states that the GEH method adheres to the guidance provided in RG 1.190.

During the AMP audit, held during the week of January 23, 2012, the staff noted that Reference 1, which is addressed below, describes the GEH method for the applicant's fluence calculations. Reference 1 also refers to Reference 2, which describes another fluence calculation method (MPM method) that the applicant used:

- Reference 1: GEH, Project Task Report, 0000-0104-5984-RO, Revision 0, "Entergy Operations, Inc., Grand Gulf Nuclear Station Extended Power Uprate," Task T0313, RPV Flux Evaluation, October 2009
- Reference 2: MPM-809633, "Grand Gulf Extended Power Uprate Neutron Transport Analysis," August 2009

In addition, the GEH report referenced above indicates the following information:

- The total fluence values at different EFPYs were calculated by adding the corresponding post-EPU fluence to the pre-EPU fluence. The post-EPU fluence and total fluence values are calculated and reported in the GEH report, while the MPM-809633 report calculated the pre-EPU fluence.
- Section 3.4.2, "Observations," of the GEH report indicates that the calculated post-EPU flux values for core shroud welds H1, V1, V2, V3, and V4 were found to be significantly lower than the pre-EPU flux values derived from MPM-809633. This section also states that, because the pre-EPU flux values were not calculated by GEH, the reason for this large difference at these locations is unknown.

Based on the information described above, the staff noted the following issues related to the applicant's fluence analysis:

- LRA Sections 4.2.1 and A.2.1.1 (UFSAR supplement for RV fluence) do not identify the methodology described in MPM-809633 as one of the methods used to calculate the neutron fluence. In addition, it is not clear which fluence calculation methods are included in the CLB.
- The LRA does not provide information on the variance between the post-EPU flux values for shroud welds H1, V1, V2, V3, and V4 based on the GEH methodology and the pre-EPU flux values derived from MPM-809633. It is not clear as to why the post-EPU flux values, which are significantly lower than the pre-EPU flux values, are acceptable.
- The LRA does not provide information to confirm how the fluence calculation methods of the applicant comply with RG 1.190.
- The LRA does not describe the results of the measurement benchmarking of the fluence calculation methods with the plant-specific dosimetry data (e.g., the first-cycle or test capsule dosimetry data) as addressed in BWRVIP-86, Revision 1, Section 5.4, "Plan for Ongoing Vessel Dosimetry." It is noted that the staff issued its SE for BWRVIP-86, Revision 1, by letter dated October 20, 2011.

By letter dated June 27, 2012, the staff issued RAI 4.2.1-2 requesting that the applicant:

- Part (a) - Justify why LRA Sections 4.2.1 and A.2.1.1 do not identify the methodology described in MPM-809633 as one of the methods that has been used to calculate and project the RV neutron fluence. Alternatively, revise LRA Sections 4.2.1 and A.2.1.1 to identify and include the MPM method in the LRA, as appropriate.

- Part (b) - As part of the response, clarify what methods for fluence calculations are included in the CLB. If the LRA does not identify all the fluence calculation methods that constitute the CLB, justify why the LRA does not identify all of them.
- Part (c) - Provide additional information on how the fluence calculation methods have been incorporated into the CLB (e.g., whether through 10 CFR 50.90 or 10 CFR 50.59 process). As part of the response, provide information to demonstrate that such methods are consistent with RG 1.190.
- Part (d) - Provide the following information related to the flux and fluence calculations:
  - Part (d.1) - Provide the pre-EPU (MPM method) and post-EPU (GEH method) flux values for core shroud welds H1, V1, V2, V3, and V4. If existent, describe any other location that involves the higher flux differences between the two calculation methods than these five core shroud welds and provide the associated flux values.
  - Part (d.2) - Clarify why the post-EPU flux values (GEH method), which are significantly lower than the pre-EPU flux values (MPM method), are acceptable in terms of the adequacy of the fluence calculations and the compatibility between the fluence calculation methods.
  - Part (d.3) - Provide the pre-EPU (MPM method) and post-EPU (GEH method) peak flux values for the inner surfaces of Shell Plates 1 and 2 at the cycle when the EPU is planned to start. If any significant difference exists between these flux values for either of the shell plates, justify why the significant difference is acceptable.
  - Part (d.4) - If pre-EPU fluence values obtained using the MPM method were combined with post-EPU fluence values obtained using the GEH method to determine total, post-EPU and end-of-life-extended fluence values, please describe the treatment of uncertainty associated with this technique, and explain how it conforms to the guidance contained in RG 1.190. If the neutron fluence values were combined, and the uncertainty treatment is not believed to adhere to RG 1.190, please justify the acceptability of this approach.
- Part (e) - Provide additional information to confirm whether the fluence calculation methods have been benchmarked with the ongoing vessel dosimetry, consistent with Section 5.4 of BWRVIP-86, Revision 1. In addition, provide information to confirm whether the fluence calculations using the implemented methods are consistent with the vessel dosimetry data.

The applicant responded to RAI 4.2.1-2 in letter dated July 25, 2012. In its response to RAI 4.2.1-2, Part (a), the applicant stated that RV neutron fluence for EPU operating conditions, through the period of extended operation, is calculated in accordance with Licensing Topical Report, “General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation,” NEDC-32983P-A, Revision 2, January 2006. The applicant also stated that pre-EPU fluence values were generated from the MPM Technologies, Inc. (MPM) analysis and the MPM analysis is consistent with the guidance contained in RG 1.190. The applicant further stated that the MPM method was approved by the NRC in its approval of a P-T limits LAR for the Nine Mile Point Unit 1 station (i.e., staff’s SE for “Nine Mile Point Nuclear Station, Unit No.1–Issuance of Amendment RE: Pressure-Temperature Limit Curves and Tables (TAC No. MB6687),” dated October 27, 2003). The applicant stated that this method is also described in UFSAR Section 4.3.2.8.

In its response to RAI 4.2.1-2, Part (b), the applicant also explained that the two fluence calculation methods included in the CLB are (1) the post-EPU GEH method which is reviewed and approved by the NRC in a SE (November 17, 2005) referenced in "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation, NEDC-32983P-A, Rev. 2" (January 2006), and (2) the pre-EPU MPM method, as approved by the NRC and described in UFSAR Section 4.3.2.8. In addition, the applicant provided revisions to LRA Sections 4.2.1 and A.2.1.1 to identify and include the MPM method as a fluence calculation method, consistent with the applicant's response.

In its response to RAI 4.2.1-2, Part (c), the applicant further addressed how the fluence calculation methods have been incorporated into the CLB. The applicant stated that the post-EPU GEH fluence method was incorporated into the CLB through the 10 CFR 50.90 process during EPU license amendment approval and is consistent with RG 1.190, as described in NEDC-32983P-A, Revision 2. The applicant stated that the pre-EPU MPM fluence method was incorporated into the CLB through the 10 CFR 50.59 process and is also consistent with RG 1.190, as described in UFSAR Section 4.3.2.8.

In its response to RAI 4.2.1-2, Part (d.1), the applicant provided the pre-EPU and post-EPU flux values for the H1, V1, V2, V3, and V4 welds. The pre-EPU and post-EPU flux values for the H1 weld are 1.04×10^{10} n/cm^2-s and 1.23×10^7 n/cm^2-s, respectively. The staff noted that the pre EPU and post-EPU flux values for the H1 weld are in good agreement with the pre-EPU and post-EPU flux values for the other welds (V1 through V4), respectively. The neutron flux values for these welds indicate a common characteristic that the pre-EPU flux value is greater than the post-EPU flux value by approximately three orders of magnitude. The staff's evaluation of this item is further described below in conjunction with RAI 4.2.1-2a.

The applicant also provided the following information regarding the flux and fluence calculations.

- In its response to RAI 4.2.1-2, Part (d.1), the applicant further stated that welds H1, V1, V2, V3, and V4 are welds on the top guide that sits above the core shroud. None of the locations evaluated in the post-EPU GEH fluence evaluation except for H1, V1, V2, V3, and V4 were found to have flux values lower than pre-EPU flux values. The apparent discrepancy between the pre-EPU flux values and the post-EPU flux values has been entered into the applicant's corrective action program (CAP).
- In its response to RAI 4.2.1-2, Part (d.2), the applicant stated that the pre-EPU values appear overly conservative, as they are associated with a location that is approximately 45 inches above the top of the active fuel, where flux values are expected to be lower than values at the top of the active fuel. Even considering the apparently conservative flux values, the resulting fluence at this location is significantly less than the peak fluence on the core shroud welds.
- In its response to RAI 4.2.1-2, Part (d.3), the applicant stated that the pre-EPU (MPM method) peak flux for the RV inner surface is 1.71×10^9 n/cm^2-s. In comparison, the post-EPU (GEH method) peak flux for the RV inner surface is 2.90×10^9 n/cm^2-s. The ratio of post-EPU to pre-EPU peak RV inner diameter flux is 1.69. Some of the increase in flux level is due to the 15 percent thermal power increase from power uprate, and additional causes include higher power in peripheral bundles due to EPU operating conditions.
- In its response to RAI 4.2.1-2, Part (d.4), the applicant stated that the position in RG 1.190 recommends that flux uncertainties be determined to provide confidence in fluence calculations. Total uncertainty values for RV and RVI flux for both pre-EPU and

post-EPU operating conditions are included in the respective fluence calculations. No specific guidance is provided in RG 1.190 regarding the combination of fluence results from multiple methods. Since both pre-EPU and post-EPU fluence values are the results of qualified methods (MPM and GEH methods), it is expected that the combination of these values is acceptable with respect to the uncertainty treatment specifications of RG 1.190.

In its response to RAI 4.2.1-2, Part (e), the applicant stated that, in accordance with paragraph 3 of Section 5.4 of BWRVIP-86, Revision 1, the post-EPU fluence calculations were performed for the applicant's RV using a methodology that was benchmarked against the RV dosimetry results from other BWRs, in accordance with the BWRVIP Integrated Surveillance Program (ISP).

In its review, the staff noted that the applicant explained that each of the fluence calculation methods (MPM and GEH methods) was approved by the NRC and the applicant incorporated each method into its current licensing basis through adequate processes. The staff also noted that measurement benchmarks were conducted on the MPM method and GEH method, as addressed in the NRC SEs dated October 27, 2003, and November 17, 2005, respectively. The staff found this portion of the applicant's response acceptable, based on the applicant's clarification.

However, the staff identified the following items that needed additional information. The staff noted that it was not clear whether the welds H1, V1, V2, V3, and V4 are core shroud welds in the top portion of the shroud cylindrical shells, as indicated in BWRVIP-02-A, or welds in the top guide as indicated in the applicant's response. The staff also noted that it was not clear whether adequate corrective actions were taken for the fluence calculations on the welds H1, V1, V2, V3, and V4 so that the applicant's corrective actions resolved the significant difference between the pre-EPU and post-EPU fast neutron flux values of these welds. The staff further noted that the 60-year fast neutron fluence (9.04×10^{18} n/cm^2) of the core spray spargers is less than the 40-year fast neutron fluence (1.50×10^{21} n/cm^2) by approximately two orders of magnitude (applicant's letter dated July 25, 2012, which addresses the response to RAI 4.7.3-1 regarding RVI). Given that the welds H1, V1, V2, V3, and V4 have post-EPU neutron flux significantly less than the pre-EPU neutron flux, the staff needed pre-EPU and post-EPU flux values for other RV locations for additional comparisons.

In addition, the staff noted that RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," Regulatory Position 1.4.1, provides guidance for analytic uncertainty analysis to support methodology qualification and uncertainty estimates (including combination of uncertainties). However, the applicant's response, addressing an expectation of acceptability, does not provide adequate information to determine how the new calculational method, which is based on adding the fluence values from the two different calculational methods together, adheres to the guidance contained in RG 1.190.

Therefore, the staff issued RAI 4.2.1-2a by letter dated September 14, 2012, requesting, in RAI 4.2.1-2a, Part (a), that the applicant clarify whether the welds H1, V1, V2, V3, and V4 are core shroud welds in the top portion of the shroud cylindrical shells. The staff requested in RAI 4.2.1-2a, Part (b), that the applicant clarify whether adequate corrective actions were taken for the fluence calculations on the welds H1, V1, V2, V3, and V4 to resolve the significant difference between the pre-EPU and post-EPU fast neutron flux values of these welds. The staff further requested in RAI 4.2.1-2a, Part (c), that the applicant resolve the issues that the 60-year fast fluence of the core spray sparger, core shroud dome, and core shroud head stud components are less than their 40-year fast fluence, in order to confirm there is no concern related to the adequacy of RV fluence calculations. In addition, the staff requested in RAI 4.2.1-2a, Part (d), that the applicant provide the pre-EPU and post-EPU flux values for the RV locations listed in LRA Table 4.2-2 to confirm that the post-EPU neutron flux values of the RV plates, welds, and nozzles are greater than the pre-EPU neutron flux values. The staff requested in RAI 4.2.1-2a, Part (e), that the applicant provide its criteria in terms of the difference between the pre-EPU and post-EPU neutron flux values to initiate a corrective action for the RV and RVI neutron fluence analysis. The staff also requested in RAI 4.2.1-2a, Part (f), that the applicant demonstrate that the combined calculational uncertainty associated with both fluence methodologies remains within RG 1.190 guidance, or provide an alternative justification for the acceptability of this method that demonstrates that it satisfies the regulations discussed in the introduction section of RG 1.190.

The applicant responded to RAI 4.2.1-2a in its letter dated October 15, 2012. In its response to RAI 4.2.1-2a, Part (a), the applicant acknowledged that H1, V1, V2, V3, and V4 are unique identifiers of the welds at the top portion of the core shroud cylindrical shell, as shown in Figure 3-9 of BWRVIP-02-A. In its response to RAI 4.2.1-2a, Part (b), the applicant stated that the location of weld H1 is well above the top of the active fuel and V1 through V4 welds are physically located above the H1 weld. The applicant stated that, therefore, the fast flux drops off dramatically above the top of the active fuel and the MPM approach used a bounding flux at these high shroud locations. The applicant further stated that this conservative assumption provided acceptable results, since these are nonlimiting shroud locations. In addition, the applicant stated that, even with this conservative assumption, the H1 fluence remained below the inspection threshold of $5x10^{20}$ n/cm^2 at 54 EFPY and this does not represent an error in the MPM evaluation or require any correction.

In its response to RAI 4.2.1-2a, Part (c), the applicant stated that errors were found in the 40-year fluence values for the RVI orificed fuel support, CS sparger, core shroud dome, and core shroud head stud components reported in its response to RAI 4.7.3-1. The applicant further provided the corrections to the fluence values and clarified that, with the corrected values, the 60-year fluence values are greater than the 40-year fluence values for these components. As part of its response, the applicant explained that the correct 40-year and 60-year fluence values for the core spray sparger are $5.73x10^{18}$ n/cm^2 and $9.04x10^{18}$ n/cm^2, respectively. In comparison, the staff noted that the applicant's previous letter dated July 25, 2012, provided an incorrect 40-year fluence value of $1.50x10^{21}$ n/cm^2.

In its response to RAI 4.2.1-2a, Part (d), the applicant provided and compared the pre-EPU and post-EPU peak neutron flux values at various RV locations, including the fast neutron peak flux values for RV beltline lower-intermediate shell and axial welds, N12 nozzles, circumferential weld AB, and lower shell/axial welds. The staff noted that the applicant's comparisons confirmed that the post-EPU flux values are reasonably greater than the pre-EPU flux levels for the RV beltline locations.

In its response to RAI 4.2.1-2a, Part (e), the applicant stated that there are no predefined values for differences between pre-EPU and post-EPU neutron flux that are used as a threshold for entry into the CAP. The applicant further explained that the reason corrective action was initiated for the H1, V1, V2, V3, and V4 welds was that pre-EPU flux was higher than post-EPU flux only for these welds and the fluence values at these weld locations remain below the weld inspection threshold of $5x10^{20}$ n/cm^2 even at 54 EFPY using the MPM method.

In its response to RAI 4.2.1-2a, Part (f), the applicant stated that it was not possible to prove the independence of all uncertainty terms used in the calculations of both fluence methods. In its response, the applicant used relative uncertainties for deriving the uncertainties for the fluence methods.

However, the staff identified concerns related to the applicant's response as follows. Specifically, the staff noted that, in its response to RAI 4.2.1-2a, Part (b), the applicant stated that the MPM method used a bounding flux value for the core shroud welds that are located at the top of the core shroud shell. However, the staff noted that the applicant did not provide specific information to justify why the flux values obtained from the MPM method are bounding-case flux values for these core shroud weld locations.

As discussed above, the staff also noted that, in its response to RAI 4.2.1-2a, Part (f), the applicant used relative uncertainties for deriving the uncertainties for the fluence methods. The staff further noted that the total uncertainty is expressed as a "relative uncertainty" combination, which is, in actuality, a weighted average of the uncertainties associated with both methods. However, the staff noted that the applicant's uncertainty analysis was not consistent with RG 1.190, and the errors associated with both fluence calculation methods are expected to propagate when the two fluence calculational methods are combined.

To address these concerns, the staff issued RAI 4.2.1-2b by letter dated November 20, 2012, requesting, in Part (a), that the applicant provide additional information to clarify why the flux values obtained from the MPM method are considered to represent bounding-case flux values for the core shroud weld locations. The staff also requested that the applicant clarify which locations are actually associated with the bounding-case flux values and why the bounding-case flux values were considered to include sufficient conservatisms for these RVI core shroud welds. In RAI 4.2.1-2b, Part (b), the staff requested that the applicant provide an analytic uncertainty analysis for the combined fluence values, consistent with the regulatory position in RG 1.190, or alternatively, the applicant provide RV neutron fluence values that were calculated using a single, NRC-approved method that has a valid and accepted analytic uncertainty analysis. This issue was identified as Open Item 4.2.1-1 in the SER with Open Items.

In its response dated January 18, 2013, the applicant addressed RAI 4.2.1-2b, Part (a) by stating that the variation of modeling between the two methods (i.e., GEH and MPM methods) resulted in significantly higher flux values for welds H1, V1, V2, V3, and V4 using the MPM method. The applicant also stated that possible contributing factors to the differing results include void fraction assumptions above the active fuel, upper-guide structure modeling, and water-column height in the area between the fuel and the shroud. The applicant further stated that, as the staff comments on BWRVIP-145-A indicate, there is significant difficulty in using the conventional discrete ordinates method in calculating fluence values for components away from the middle plane of the core.

In addition, the applicant stated that the shroud welds (H1, V1, V2, V3, and V4 welds) are the only welds in the vessel or shroud where pre-EPU neutron flux values were higher than post-EPU neutron flux values. The applicant stated that the most important top guide locations for considering the effects of fluence are areas at the lower elevations of the top guide, where the highest neutron flux and fluence occur near the center of the core. The applicant also indicated that the BWRVIP has determined that the top guide is susceptible to IASCC, since the fluence on the top guide exceeds the screening threshold of 5×10^{20} n/cm^2 for the period of extended operation. The applicant further stated that both the MPM and GEH models indicate that the neutron fluence on the top guide exceeds the IASCC threshold and that the applicant follows the inspection and evaluation guidelines that are described in BWRVIP-26-A in order to manage IASCC for the top guide.

In its response to RAI 4.2.1-2b, Part (b), the applicant discussed the summation of pre-EPU and post-EPU peak fluence values from two different fluence methods and associated uncertainty calculations, as follows. The applicant indicated that it determined the 54-EFPY fluence by adding the MPM pre-EPU fluence for 22.99 EFPY and the GEH post-EPU fluence for the remaining 31.01 EFPY. The applicant also indicated that the neutron fluence values associated with the maximum uncertainties for the MPM pre-EPU and the GEH post-EPU calculational basis are as follows:

- MPM pre-EPU peak fluence with 16 percent uncertainty: $1.32\text{x}10^{18} \pm 2.11\text{x}10^{17}\text{n/cm}^2$
- GEH post-EPU peak fluence with 19 percent uncertainty: $3.12\text{x}10^{18} \pm 5.92\text{x}10^{17}\text{ n/cm}^2$

The applicant further stated that both uncertainty values are reported as relative (percentage) and that absolute uncertainty may be determined by combining an absolute calculated fluence value with its associated relative uncertainty. The applicant indicated that the relative uncertainty of the combined total fluence is calculated by using the root-sum-of-squares (i.e., $\sqrt{((2.11\text{x}10^{17})^2+(5.92\text{x}10^{17})^2)} = 6.29\text{ x}10^{17}$). The applicant also indicated that it determined the absolute uncertainty by dividing the root-sum-squares by the absolute total fluence value, such as, $6.29\text{ x}10^{17}/(1.32\text{x}10^{18} + 3.12\text{x}10^{18}) = 14.17$ percent.

In its response, the applicant also stated that the independence of all uncertainty terms between the two fluence methods cannot be proven, as it is known that both fluence analyses involve a 2D flux synthesis and discrete ordinates transport calculation using the same DORT code. The applicant further stated that, given that independence of all uncertainty terms cannot be proven, a conservative approach may be adopted and the provisional error propagation technique for uncertainties in sums of direct measurements may be used, where, in adding quantities, the uncertainties in those quantities are simply added as well. In addition, the applicant indicated that the maximum total uncertainty is calculated by this method as follows: $(2.11\text{x}10^{17} + 5.92\text{x}10^{17})/(1.32\text{x}10^{18} + 3.12\text{x}10^{18}) = 18.11$ percent.

The applicant stated, as the staff indicated in the issue discussion of RAI 4.2.1-2b, the uncertainty associated with adding the two fluence values together should be higher than either as a stand-alone calculation. However, the applicant stated that, since the total combined fluence is also higher than the fluence from the individual stand-alone calculations, the relative uncertainty for the total of fluence is between the relative uncertainty of the individual calculations.

The staff also noted that, since the method used to perform the MPM fluence calculations is not documented in an NRC-approved methodology, a detailed description of the calculative methods, and their qualification, as both pertain to GGNS, must be submitted for NRC staff review and approval for referencing in the LRA. This information will enable the staff to reach a determination regarding whether the MPM fluence calculations are adherent to RG 1.190, or are otherwise acceptable. Similarly, the staff has determined that the applicability of the GEH fluence methodology to GGNS should also be established. This effort may include plant-specific dosimetry comparisons, or establishing that the existing qualification contained in NEDC-32983P-A is adequate.

The staff also noted that the use of a combined method (using fluence from two separate methods) requires an additional analytic uncertainty analysis and an extensive amount of further validation and verification. Since the staff is not aware of any such combined method being approved in the past, such a proposal would require significant review to determine whether this approach could be found to comply acceptably with NRC guidance or not. For example, any codependent terms in the uncertainty associated with either method must be appropriately treated in the analysis, and any uncertainties associated with either method that could propagate must be evaluated. The staff further noted that the significant difference in neutron flux values associated with each method (limiting location flux values differ by approximately 70 percent) warrants an additional evaluation of the causes, and GGNS would need to provide extensive justification.

In addition, the staff noted that the applicant's response did not clearly address why the modeling variation between the MPM and GEH methods resulted in the MPM method yielding conservative bounding-case flux values for core shroud welds H1, V1, V2, V3, and V4.

By letter dated August 28, 2013, the staff issued RAI 4.2.1-2c requesting additional information to resolve the issues discussed above. In RAI 4.2.1-2c, the staff requested additional information, as follows:

- Part 1(a): Provide a detailed description of the MPM fluence calculations and their results, including the methods and data sets used to perform the calculations, the analytic representation of the reactor geometry, and the problem setup, execution, and post-processing.
- Part 1(b): Provide a description of the qualification of the MPM fluence calculational methods in sufficient detail to establish adherence to RG 1.190 as it applies to the BWR/6 design and GGNS, in particular, or sufficient details to demonstrate to the staff that the calculations are otherwise acceptable for use at GGNS.
- Part 1(c): Provide information to demonstrate that the GEH analytic method is suitably qualified for analysis of the GGNS RV.
- Part 1(d): Provide a detailed, analytic uncertainty analysis that accounts for any additional uncertainty or bias associated with adding fluence values together from these two methods (MPM and GEH methods), and benchmarking information to show that the results of the vessel fluence analyses remain valid when combined.
- Part 1(e): Provide information to establish that the difference between the two flux values calculated using the different methods is valid. For example, compare the two methods in calculational benchmarks; provide an estimate of the pre-EPU fluence using GEH calculational method; and provide an estimate of the post-EPU fluence using MPM calculational method)
- Part 2: Provide a description, including a technical basis, for each of the different calculational methods that are used to determine the fluence values of the RVI. For each of the RVI components, describe the fluence calculational method used for the component. In addition, explain why the use of different calculational methods is adequate to determine the fluence values of the RVI.
- Part 3: Justify the acceptability of using different methods to calculate related phenomena (e.g., neutron fluence) that all stem from the same source (e.g., the GGNS reactor core), for different surfaces (i.e., nozzles, beltline welds, vessel surface, and upper internals), as opposed to choosing one method to apply to all the surfaces.
- Part 4: Clarify why the modeling variation between the MPM and GEH methods results in conservative bounding-case flux values for the core shroud weld locations (H1, V1,

V2, V3, and V4) using the MPM method. As part of the response, the applicant should clarify whether the MPM or GEH method approximates the region above the reactor core as water, without explicitly modeling the stainless steel top guide.

- Part 5(a)(i): If the method is NRC-approved insofar as it applies to vessel fluence calculations, the applicant should provide the reference to the staff-accepted methodology.
- Part 5(a)(ii): If the method is not NRC-approved, the applicant provide the plant-specific calculations and documentation, and include sufficient information, to enable the NRC staff to determine whether the calculation adheres to RG 1.190, or other justification, as required to establish that the applicant's fluence calculation is acceptable.
- Part 5(a)(iii): The applicant's response regarding Part 5(a)(i) and 5(a)(ii) should be consistent with Regulatory Position 3, "Reporting," for the specific documentation required to establish adherence to RG 1.190.
- Part 5(b): The applicant should confirm whether, and describe how, the remaining neutron fluence-related TLAAs are affected by this new fluence calculation.

The staff issued RAI 4.2.1-2c with the expectation that the applicant would either respond to the requests in Parts 1-3 of RAI 4.2.1-2c, or, alternatively, to the requests in Part 5(a) of the RAI, which would apply if the applicant is using the option to apply a single neutron fluence methodology for the TLAA basis. The applicant was also to provide its response to the requests in Parts 4 and 5(b) of the RAI.

In its letter dated September 23, 2013, the applicant responded to RAI 4.2.1-2c and indicated that it would respond to Part 5 of RAI 4.2.1-2c, in lieu of providing responses to parts1–3 of the RAI. The applicant further indicated that the supplemental response to part 5 of RAI 4.2.1-2c would be submitted within 7 to 9 months from the date of the letter providing the response to RAI 4.2.1-2c.

The applicant also responded to RAI 4.2.1-2c, Part 4, in the letter of September 23, 2013. In its response, the applicant stated that the MPM method specifically includes modeling of the stainless steel top guide using a mixture that includes Inconel or stainless steel in addition to Zircaloy, depending on the fuel type. The applicant also stated that, above the top guide, the steam exiting the reactor is also modeled to provide a conservative bounding-case flux value for the upper welds on the core shroud.

In comparison, the applicant stated that the GEH method also considers the stainless steel top guide. The applicant stated the difference between the methods is in GEH's modeling of the area above the top guide. The applicant also stated that GEH originally modeled this area with steam and stainless steel that extended up to the H1 weld. The applicant further explained that an updated GEH evaluation without the stainless steel above the top guide resulted in higher flux values at the H1, V1, V2, V3, and V4 welds that are more consistent with those predicted by the MPM method when adjusted for the EPU power level.

In its review, the staff finds the applicant's response to RAI 4.2.1-2c, Part 4, acceptable, because (1) the applicant clarified that the difference in fluence values at the upper welds of the core shroud resulted from the difference in modeling for the area above the top guide between the MPM and GEH methods, and (2) the applicant confirmed that the updated GEH fluence values, based on the modeling without unnecessary stainless steel material above the top guide, are consistent with the MPM fluence values for these welds when adjusted for the EPU. The staff's concern described in RAI 4.2.1-2c, Part 4, is resolved.

In its subsequent letter dated May 14, 2015, the applicant updated the status of the response to Part 5 of RAI 4.2.1-2c. The applicant indicated that GGNS submitted an LAR to the NRC staff to adopt the MPM method of calculating RV neutron fluence values as a single fluence method in accordance with RG 1.190. The applicant also indicated the LAR is documented in Entergy letter, GNRO-2014/00080, dated November 21, 2014. The applicant further indicated that NRC staff's review of the LAR is in progress and that, once the MPM method is approved as a single fluence methodology for CLB, it will submit information that was requested in Part 5 of RAI 4.2.1-2c.

By letter dated September 1, 2015, the applicant supplemented their response to RAI 4.2.1-2c, Part 5(a), stating that the MPM method of calculating RV neutron fluence at GGNS was NRC approved on August 18, 2015, and that Amendment No. 204 to License No. NPF-29 was issued on August 18, 2015 (ADAMS Accession No. ML15229A218). The applicant also indicated that, because the fluence calculation method is approved by the NRC, it provided the reference (i.e., August 18, 2015, letter of the NRC) to the staff-approved MPM method in accordance with option (i) of RAI 4.2.1-2c part 5(a).

The staff noted that, on August 18, 2015, the staff issued a license amendment and safety evaluation (SE) approving the use of the MPM method as a single fluence calculational method that incorporated the method into the CLB of GGNS. The NRC SE verified that the method adheres to the recommended fluence methodology criteria in RG 1.190. As part of the verification, the SE confirmed that a dosimetry benchmark calculation for GGNS Cycle 1 was in excellent agreement with the dosimetry measurements.

In its review, the staff finds that the applicant's response to RAI 4.2.1-2c, Part 5(a) is acceptable, because (1) the applicant provided the relevant reference to the staff-approved single fluence method (i.e., MPM method) that was approved in the staff's August 18, 2015, SE, (2) the approved method, consistent with RG 1.190, was incorporated into the CLB by License Amendment No. 204, and (3) the additional actions of the applicant, which are specified in the staff's August 18, 2015, SE, will ensure adequate qualification of the fluence method for the locations outside the original beltline region (e.g., comparison of fluence calculations with dosimetry measurements at core shroud locations above the active core region). The concern described in Part 5(a) of RAI 4.2.1-2c is resolved. The staff finds that this approved license amendment resolves the concerns described in RAI 4.2.1-2, Parts (a), (b), and (c).

By the letter dated July 29, 2015, the applicant also addressed its response to Part 5(b) of RAI 4.2.1-2c. In its response, the applicant provided revisions to the RV neutron embrittlement TLAAs described in LRA Section 4.2. These revisions are based on the revised 54-EFPY fluence values that were calculated by using the staff-approved MPM method. In its response, the applicant also revised the UFSAR supplement for the neutron embrittlement TLAAs to be consistent with the revisions to these TLAAs.

In its revision to LRA Section 4.2.1 for neutron fluence, the applicant explained that the RV neutron fluence is calculated by using the staff-approved MPM method. The applicant also indicated that the projected peak RV fluence ($E > 1$ MeV) for 54 EFPY is revised from 4.44×10^{18} n/cm^2 to 4.02×10^{18} n/cm^2 (approximately 9.5 percent decrease). The applicant further indicated that the revised 54-EFPY fluence values extend the RV beltline region that is exposed to the fluence level exceeding 1×10^{17} n/cm^2. The applicant identified the following components as additional RV beltline components with neutron fluence exceeding 1×10^{17} n/cm^2 for 54 EFPY:

- Upper intermediate shell (Shell Ring 3) and its associated axial welds and circumferential weld (Weld AC)
- N6 LPCI nozzles

The staff considered these additional beltline materials in its evaluation of the applicant's disposition of TLAAs in the remaining subsections of SER Section 4.2.

Furthermore, the applicant revised LRA Section A.2.1.1 (UFSAR supplement) for the neutron fluence TLAA, consistent with the applicant's response.

In its review, the staff finds that the applicant's response to RAI 4.2.1-2c, Part 5(b) acceptable because (1) the applicant adequately revised LRA Section 4.2.1 to provide the projected RV fluence for 54 EFPY as calculated by using the staff-approved fluence method, (2) the applicant's revision to the LRA identifies additional beltline components that will have a 54 EFPY neutron fluence exceeding 1×10^{17} n/cm^2 based on the revised fluence projections, (3) the applicant adequately revised the UFSAR supplement for the RV neutron fluence TLAA, and (4) the applicant also provided revised neutron embrittlement TLAAs based on the revised 54-EFPY fluence values. The staff's evaluations of the other neutron embrittlement TLAAs are described in Sections 4.2.2 through 4.2.6 of this SER. The staff's concern described in Part 5(b) of RAI 4.2.1-2c is resolved.

As discussed above, the staff finds that the applicant adequately evaluated the TLAA for the RV neutron fluence because (1) the applicant adequately identified neutron fluence calculations as a neutron embrittlement TLAA, (2) the applicant incorporated the staff-approved fluence method into the CLB through the license amendment process, (3) the applicant performed 54-EFPY fluence calculations in accordance with the staff-approved method that is consistent with the guidance in RG 1.190, and (4) the applicant's analysis provides neutron fluence projections to the end of the period of extended operation (54 EFPY). Open Item 4.2.1-1 is closed.

4.2.1.3 UFSAR Supplement

LRA Section A.2.1.1 provides the UFSAR supplement summarizing the fluence analysis for the RV. The staff reviewed LRA Section A.2.1.1 consistent with SRP-LR Section 4.2, which indicates that the applicant identifies (a) the neutron fluence at the expiration of the license renewal period, (b) the staff-approved methodology used to determine the neutron fluence (or submits the methodology for staff review), and (c) whether the methodology follows the guidance in RG 1.190.

As previously discussed, in its response dated July 25, 2012, to RAI 4.2.1-1, the applicant provided revisions to LRA Sections 4.2.1 and A.2.1.1 (UFSAR supplement) to identify both of the MPM and GEH fluence calculation methods as part of the CLB. As part of its response dated October 15, 2012, to RAI 4.2.1-1a, the applicant also identified the RV neutron fluence calculations as a TLAA and dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(ii). In addition, the applicant provided relevant revisions to the UFSAR supplement to include the MPM method and TLAA disposition in the UFSAR supplement.

As documented in Section 4.2.1.2 of this SER, the applicant revised LRA Section A.2.1.1 by letter dated July 29, 2015, in response to RAI 4.2.1-2c(5)(b), to clarify that the RV neutron fluence analysis is performed by using the staff-approved MPM method. Based on the staff's review of the UFSAR supplement, the staff finds that the applicant provided an adequate summary description of the neutron fluence analysis, 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 RV fluence analysis has 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 Pressure-Temperature Limits

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2, as amended in the applicant's letter of July 29, 2015, describes the applicant's TLAA for calculating the pressure-temperature limits (P-T) limits that will be needed to safely operate the plant during normal and transient operating conditions (including heatups and cooldowns) and during pressure testing conditions for the plant. The current P-T limits of the applicant are located in a Pressure-Temperature Limits Report (PTLR) that was submitted to the NRC staff by letter dated September 8, 2010. The current P-T limits were approved up to 35 EFPY as part of the recently approved EPU amendment (NRC letter dated July 18, 2012).

The Reactor Vessel Surveillance Program provides data to update the P-T limits. Prior to exceeding 35 EFPY, the applicant is required to develop new P-T limits for higher fluence values in accordance with the requirements in Administration Controls Section 5.6.6 of the plant's TS (TS Section 5.6.6).

The applicant dispositioned the TLAA for P-T limits in accordance with 10 CFR 54(c)(1)(iii), that the effects of reduction in fracture toughness of the reactor vessel will be adequately managed by the Reactor Vessel Surveillance Program and the updates of P-T limits for the period of extended operation.

4.2.2.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the P-T limits and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with SRP-LR Section 4.2.3.1.3.3, which states that updated P-T limits for the period of extended operation must be available prior to entering the period of extended operation. SRP-LR Section 4.2.3.1.3.3 also states that the 10 CFR 50.90 process for P-T limits located in the limiting condition of operations or the Administrative Controls Process for P-T limits that are administratively amended through a PTLR process can be considered adequate aging management programs within the scope of 10 CFR 54 21(c)(1)(iii), such that P-T limits will be maintained through the period of extended operation.

The staff noted that the applicant is using TS Section 5.6.6 (as approved in Facility License Amendment No. 191) and its approved PTLR process as the basis for accepting this TLAA in accordance with 10 CFR 54.21(c)(1)(iii). This TS section requires that any future updates of the P-T limits and the PTLR containing the P-T limits must be done in accordance with the methods of analysis in Proprietary General Electric-Hitachi Topical Report (TR) No. NEDC-33178P-A, Revision 1, "GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure

Vessel Temperature Curves" (June 2009). The staff noted that TS Section 5.6.6 also requires the applicant to provide the PTLR to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement of the PTLR.

The staff noted that the current PTLR and P-T limit curves are valid for operation up to 35 EFPY and were approved by the staff on July 18, 2012, in License Amendment No. 91 for the applicant's EPU. Prior to the period of extended operation, the applicant will be required to update its P-T limit curves in accordance with the requirements in 10 CFR Part 50, Appendix G, and TS Section 5.6.6, including consideration of the additional materials identified with neutron fluence exceeding 1×10^{17} n/cm^2 for 54 EFPY. The applicant will submit the PTLR containing the updated curves to the NRC for information. The staff noted that the applicant's implementation of the approved methodology in TR NEDC-33178P-A, Revision 1, will ensure that the updated P-T limits will include appropriate safety margins on fracture and will incorporate the minimum temperature requirements that are specified in 10 CFR Part 50, Appendix G. The staff noted that the approved methodology will also ensure that the calculation of the P-T limits will consider the impact that increasing fluence induced by plant operations will have on the limiting adjusted reference temperature (ART) values used in the P-T limit calculations. The calculations of the P-T limits will incorporate plant-specific embrittlement information and surveillance data obtained from the applicant's Reactor Vessel Surveillance Program (i.e., the BWRVIP ISP for the facility (see LRA Section B.1.38)).

Based on this review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reduction in fracture toughness due to neutron embrittlement of the reactor vessel will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.3 because the applicant continues to update the P-T limits in accordance with 10 CFR Part 50, Appendix G, such that the P-T limits for the period of extended operation will be available prior to the period of extended operation in a consistent manner that the current P-T limits were approved up to 35 EFPY. The staff's evaluation of the applicant's Reactor Vessel Surveillance Program is given in Section 3.0.3.1.36 of this SER.

4.2.2.3 UFSAR Supplement

LRA Section A.2.1.2, as amended in the letter of July 29, 2015, provides the UFSAR supplement summarizing the applicant's TLAA for P-T limits. The staff reviewed LRA Section A.2.1.2, consistent with 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. The SRP-LR also states that Table 4.2-1 of the SRP-LR contains examples of acceptable UFSAR supplement information for this TLAA and the reviewer verifies that the applicant has provided a UFSAR supplement with information equivalent to that in SRP-LR Table 4.2-1.

The staff noted that the UFSAR supplement states that "the P-T limits will continue to be updated, as required by 10 CFR Part 50, Appendix G." However, the requirements in 10 CFR Part 50, Appendix G, establish the minimum safety margin and minimum operating temperature requirements that must be factored into the calculations of P-T limits and that do not establish any criteria on when the updates of P-T limits must be performed in accordance with the CLB. Instead, the staff noted that the criteria for performing updates of the P-T limits are established in TS Section 5.6.6.

By letter dated October 28, 2015, the staff issued RAI 4.2.2-1, in which the staff requested clarifications on this matter. Specifically, the staff asked the applicant to justify why UFSAR Supplement Section A.2.1.2 did not specify that updates of the P-T limits would be performed in accordance with the requirements stated in TS Section 5.6.6.

The applicant responded to RAI 4.2.2-1 in a letter dated November 23, 2015. In its response to RAI 4.2.2-1, the applicant amended UFSAR Supplement Section A.2.1.2 to indicate that the updates of the P-T limits will be performed in accordance with requirements for P-T limits in 10 CFR Part 50, Appendix G, and in accordance with requirements in TS Section 5.6.6 for updating the P-T limits using the applicant's PTLR process. The applicant also stated that the TLAA for the plant P-T limits is acceptable in accordance with 10 CFR 54.21(c)(1)(iii). The staff finds the amended version of UFSAR Supplement Section A.2.1.2 to be acceptable because: (a) the basis for updating the P-T limits using 10 CFR Part 50, Appendix G, and TS Section 5.6.6 requirements is consistent with the CLB, and (b) the requirements and bases in the CLB for updating the P-T limits provide an acceptable basis for managing loss of fracture toughness due to neutron irradiation embrittlement in the ferritic shell, nozzle, and weld components of the reactor vessel during the period of extended operation. RAI 4.2.2-1 is resolved.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.2.3.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for P-T limits, 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 provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of neutron irradiation embrittlement on the intended function of the reactor vessel will be adequately managed by the Reactor Vessel Surveillance Program in conjunction with the applicant's updates of the P-T limits 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).

4.2.3 Upper-Shelf Energy

The regulations in 10 CFR Part 50, Appendix G, provide the Commission's requirements for minimum levels of reactor vessel Charpy USE. The rule requires the Charpy USE values of reactor vessel components made from ferritic steel materials to be greater than or equal to a minimum acceptable value of 50 ft-lb throughout the licensed life of the plant. Owners of plants that cannot demonstrate compliance with this acceptance criterion are allowed by the rule to submit a supplemental SE (i.e., equivalent margins analysis [EMA]) for NRC approval in order to demonstrate that lower values of Charpy USE will provide margins of safety against fracture equivalent to those specified and required in Appendix G of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1 (ASME Section XI, Appendix G).

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3, as amended in the applicant's letter of July 29, 2015, describes the applicant's TLAA for Charpy USE values for the period of extended operation (i.e., through 54 EFPY of plant operations).

Charpy USE values for most of the applicant's reactor vessel materials were determined in accordance with RG 1.99, Revision 2, Regulatory Position 1.2, which is applied in cases where reactor vessel surveillance data are not available. The exceptions are a plate material with Heat No. A1224-1 and a weld material with Heat No. 5P6214B (single and tandem), which are included in the BWRVIP ISP. These are the only materials that have credible surveillance data for the USE analysis such that Regulatory Position 2.2 of RG 1.99, Revision 2, was used to compute the USE values.

In the letter of July 29, 2015, the applicant provided updated USE calculations and values for the following types of components located in the beltline regions of the reactor: (a) shell plates in Shell Nos. 1, 2, and 3 of the reactor vessel, (b) axial weld components in Shell Nos. 1, 2, and 3 of the reactor vessel, (c) circumferential welds AB and AC used as the circumferential weld seams for the three reactor vessel beltline shell courses, (d) the N-6 nozzle forging and its nozzle-to-vessel weld, and (e) the N-12 nozzle materials and their nozzle to vessel welds. The applicant identified that the reactor vessel USE values were limited by the plate material that was made from the Heat C2779-1 in Shell Ring No. 3 of the reactor vessel. The applicant stated that, since it could not demonstrate that the USE value for this shell plate would remain above 50 ft-lb at the end of the period of extended operation, it performed an EMA for the component that covers 54 EFPY.

Based on this assessment, the applicant stated that the USE values (as presented in LRA Table 4.2-2) demonstrate that all beltline materials remain above the 50 ft-lb criterion in 10 CFR Part 50, Appendix G, or they have been demonstrated to have acceptable levels of USE through performance of an EMA. The applicant stated that the USE analyses (including the EMA for the plate made from Heat C2779-1) have been projected to the end of the period of extended operation and are acceptable in accordance with the criterion in 10 CFR 54.21(c)(1)(ii).

4.2.3.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the USE values of the reactor vessel materials and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with SRP-LR Section 4.2.3.1.1.2, which states that the documented results of the revised USE analysis based on the projected neutron fluence at the end of the period of extended operation are reviewed for compliance with 10 CFR Part 50, Appendix G. In its review, the staff confirmed that the chemistry and initial USE values provided in LRA Section 4.2.2 are consistent with those provided in the recent LAR for a power uprate (approved by the staff on July 18, 2012); therefore, the technical information in LRA Section 4.2.2 is consistent with the applicant's CLB. The staff also reviewed the USE values against the requirements of 10 CFR Part 50, Appendix G.

The regulations in 10 CFR Part 50, Appendix G, require the USE values of ferritic components in the beltline of the reactor vessel to be greater than or equal to 50 ft-lb in the irradiated condition throughout the licensed life of the plant. Owners of plants that cannot demonstrate compliance with this acceptance criterion are allowed to submit an EMA for NRC approval in order to demonstrate that lower values of Charpy USE will provide margins of safety against fracture equivalent to those specified and required in Appendix G of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1 (ASME Section XI, Appendix G).

The predicted decrease in USE values due to neutron embrittlement during plant operation depends on the type of material (weld or base plate), the amount of copper in the material, and the predicted neutron fluence for the material, as described in RG 1.99, Revision 2.

RG 1.99, Revision 2, also addresses two acceptable approaches to project the USE values for ferritic steels. In accordance with RG 1.99, Revision 2, Regulatory Position 1.2, the applicant may use the curves of percent decrease in USE as a function of the material type, copper content, and neutron fluence, which are provided in RG 1.99, Revision 2 (in the absence of credible reactor vessel surveillance data). Alternatively, the applicant may determine the percent decrease in USE based on the reactor vessel surveillance data if credible surveillance data are available, in accordance with RG 1.99, Revision 2, Regulatory Position 2.2. In LRA Section 4.2.3, the applicant indicated that plate Heat No. A1224 and weld Heat No. 5P6214 are the only materials for which surveillance test data are available and the surveillance data were used to determine their USE values.

In its review, the staff confirmed that the applicant determined the USE values of the reactor vessel beltline materials, consistent with RG 1.99, Revision 2, with the exception of the following item that needed further clarification. It was not clear to the staff how the applicant determined the copper content of Shell Plate 1 Heat C2506-1, which had the lowest USE value (58.5 ft-lb) listed among the reactor vessel beltline materials. Note 2 of LRA Table 4.2-2 indicates that since information is not available for the actual measured copper content for this plate, the maximum allowable copper content was obtained from the vessel design specification (i.e., copper content of 0.12 percent).

In comparison, RG 1.99, Revision 2, specifically recommends that best estimate compositions of the materials be used, which are the mean values of measured composition data for a given material. If such best-estimate composition values are not available, upper limiting values given in the material specification are acceptable. Conservative estimates of the chemistry (mean plus one standard deviation) based on generic data may be used if justification is provided. However, the staff noted that RG 1.99, Revision 2, does not specifically address the use of the composition data described in a design specification to determine the level of neutron embrittlement for reactor vessel materials.

By letter dated June 27, 2012, the staff issued RAI 4.2.3-1 requesting, in Part (a), that the applicant provide the part of the design specification for Shell Plate 1 that describes the required copper content and the material specification that was in effect when the reactor vessel for GGNS was built. The staff also requested, in RAI 4.2.3-1, Part (b), that the applicant describe the documented basis for the copper content of Shell Plate 1 Heat C2506-1, such as available certified material test reports (CMTRs), quality control documents, and/or other data that might be used to justify the assumed copper content (i.e., copper content of 0.12 percent).

By letter dated July 26, 2012, the applicant responded to RAI 4.2.3-1, Part (a), and stated that the reference to the design specification in Note 2 of LRA Table 4.2-2 was in error, and the correct reference is the purchase specification. The applicant stated that a revision to Note 2 of LRA Table 4.2-2 was included in the RAI response to change “design specification” to “purchase specification.” As described in SER Section 4.2.1.2, the applicant provided a subsequent RAI response by letter dated July 29, 2015, in part to re-evaluate the neutron embrittlement TLAAs to account for the updated neutron fluence values. This response changed “purchase specification” back to “design specification” in this note, which became Note 8 in the amended LRA Table 4.2-2. By letter dated February 26, 2016, the applicant corrected Note 8 in LRA Table 4.2-2 to again reference the “purchase specification”. In addition, the applicant indicated that in order to justify the use of 0.12 percent copper for the USE calculations for Shell Plate 1 Heat C2506-1, all available BWR/6 fleet vessel CMTRs were reviewed. The applicant further stated that in the review, 28 data points were located, and it was found that mean plus two times the standard deviation results in 0.10 percent copper. The applicant stated that based on the reviewed data, it is shown that 0.12 percent copper is greater than the upper bound for all available BWR/6 copper content. The applicant's response to RAI 4.2.3-1, Part (b), cited the response to Part (a).

The staff reviewed the applicant's response and finds the use of 0.12 percent copper for the USE evaluation for Shell Plate 1 acceptable because 0.12 percent is a statistically-based conservative estimate for the plate based on the staff's review of the generic data. RAI 4.2.3-1, Parts (a) and (b) are resolved.

By letters dated July 29, 2015 and November 23, 2015, the applicant amended the LRA and updated the USE calculations to account for the new neutron fluence methodology and neutron fluence values (as projected to 54 EFPY) that were submitted for resolution of RAI 4.2.1-2c(5)(b).

The staff noted that the updated USE assessments apply to the following reactor vessel beltline components, which include the additional materials with neutron fluence exceeding $1x10^{17}$ n/cm^2 for 54 EFPY: (a) shell plates in Shell Rings 1, 2, and 3 of the reactor vessel, (b) axial weld components in Shell Rings 1, 2, and 3 of the reactor vessel, (c) circumferential welds AB and AC used as the circumferential welds seams for the three reactor vessel beltline shell courses, (d) the N-6 nozzle forging and its nozzle-to-vessel weld, and (e) the N-12 nozzle materials and their nozzle to vessel welds. The staff also noted that the applicant performed the USE calculations issuing the method of analysis in Regulatory Position 2.1 of RG 1.99, Revision 2, and the method of analysis in Regulatory Position 2.2 of the RG, which incorporates applicable data from the BWRVIP ISP into the USE calculations for these reactor vessel plate, nozzle, and weld components.

The staff noted that the USE TLAA is limited by the USE calculation for the Shell Plate 3 component made from Heat C2779-1, which is the only RPV heat that does not meet the 50 ft-lb criterion in Appendix G to 10 CFR Part 50. The staff also noted that the applicant performed an EMA for this component because the applicant could not demonstrate that the USE value of the component would remain above 50 ft-lb through 54 EFPY of plant operations. However, the staff determined that the letter of July 29, 2015, did not include the EMA as an enclosure, or if previously approved by the staff, reference the plant records containing the EMA and the NRC SE issued in approval the EMA. Therefore, the staff could not tell whether the staff previously approved the referenced EMA. If the staff did not previously approve the EMA, the staff noted that it would need to be processed and reviewed for staff approval as part of the LRA review, since this is required by the regulations in 10 CFR Part 50, Appendix G.

By letter dated October 28, 2015, the staff issued RAI 4.2.3-2, Parts (1) and (2) to the applicant. In Part (1) of this RAI, the staff asked the applicant to clarify whether the EMA for the referenced RPV shell plate (as referenced in Note 10 of LRA Table 4.2-2) was submitted and approved by the staff. If the EMA was previously approved by the staff, the staff asked the applicant to identify the date of the staff's SE (and if available, the ADAMS Accession No. or NRC microfiche Accession No. associated with the SE) that approved the EMA for incorporation into the licensing basis. Otherwise, if the EMA was not previously approved, the staff asked the applicant to provide its basis for why the EMA was not included in the letter of July 29, 2015, and submitted for staff approval, as required by 10 CFR Part 50, Appendix G. In RAI 4.2.3-2, Part (2), the staff asked the applicant to identify the USE value that is associated with the RPV shell plate made from Heat C2779-1 at 54 EFPY.

The applicant responded to RAI 4.2.3-2, Parts (1) and (2), in a letter dated December 14, 2015. In its response to Part (1) of the RAI, the applicant clarified that the specific EMA that is being applied to the RPV shell plate made from Heat C2779-1 for the renewed licensing basis is the generic EMA for BWR 3 – 6 RPV plate components in EPRI BWRVIP Report No. 1008882, "BWRVIP-74-A: BWR Vessel and Internals Project: BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal" (BWRVIP-74-A), dated June 2003. In its response to RAI 4.2.3-2, Part (2), the applicant clarified that the USE value for this plate component is projected to be 47 ft-lb at 54 EFPY.

In its response to RAI 4.2.3-2, the applicant also amended Note 10 of LRA Table 4.2-2 to state the following (as applied to the EMA for the RPV shell plate made from Heat C2779-1):

> USE is projected to be reduced by 9.5% over the license period of 0 EFPY to 54 EFPY. Considering the necessary adjustment resulting from the … ISP results, the reduction remains at 9.5% resulting in a 54 EFPY USE of 47 ft-lb. Therefore, EMA methods described in BWRVIP-74-A were applied. Since projected USE at 54 EFPY is greater than the minimum allowable USE of 35 ft-lb from BWRVIP-74-A, this material remains qualified.

The staff noticed that the applicant's response to the RAI demonstrated compliance with these regulatory requirements by confirming or identifying that: (a) the USE analysis for the GGNS RPV is limited by the USE analysis for the RPV shell plate made from Heat C2779-1, (b) the USE value for this RPV component at 54 EFPY (i.e., 47 ft-lb) is less than the 50 ft-lb requirement in 10 CFR Part 50, Appendix G, (c) the generic EMA for BWR RPV plate components in BWRVIP-74-A will be applied to the renewed licensing basis for the period of extended operation, and (d) the USE value of 47 ft-lb for the limiting RPV plate component at 54 EFPY is acceptable because it is bounded by the lowest USE value (i.e., 35 ft-lb) approved for BWR RPV shell plate components in the BWRVIP-74-A EMA.

The staff performed an independent calculation of the USE value for this limiting shell plate in accordance with RG 1.99, Revision 2, and verified that the USE value for this component at 54 EFPY is projected to be 47 ft-lb. The staff verified that the generic EMA for BWR RPV shell plate components in the BWRVIP-74-A report was approved in an SE dated October 8, 2001 (ADAMS Accession No. ML012920549), and that the NRC's SE approved USE values for BWR RPV shell plate components as low as 35 ft-lb. Therefore, the staff confirmed that the applicant has projected the USE analysis for limiting RPV beltline plate components to the end of the period of extended operation and has adequately demonstrated that the USE value will remain above the lowest EMA-approved USE value for BWR RPV plate components stated in the BWRVIP-74-A report. The staff also verified that the applicant has adequately projected the USE values for the remaining RPV beltline components in accordance with 10 CFR 54.21(c)(1)(ii) and has demonstrated that the USE values will be in excess of 50 ft-lb at the end of the period of extended operation, as required in accordance with 10 CFR Part 50, Appendix G. RAI 4.2.3-2, Parts (1) and (2), are resolved.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE analyses for the reactor vessel beltline materials have been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.2.2.1.1.2 because the applicant projected the USE values to the end of the period of extended operation in accordance with RG 1.99, Revision 2, and it has adequately demonstrated that they will either: (a) meet the 50 ft-lb USE requirement stated 10 CFR Part 50, Appendix G, or (b) for the EMA that applies to the limiting RPV beltline plate component, the USE value for the component at 54 EFPY will be above the 35 ft-lb USE value approved in BWRVIP-74-A for BWR RPV shell plate components.

4.2.3.3 UFSAR Supplement

LRA Section A.2.1.3 provides the UFSAR supplement summarizing the TLAA of the USE for reactor vessel beltline materials. By letter dated July 29, 2015, the applicant amended the UFSAR supplement for this TLAA to indicate that the USE analyses for the reactor vessel beltline components have been projected to 54 EFPY and are acceptable because they either have been demonstrated to be above the 50 ft-lb acceptance criterion requirement stated in 10 CFR Part 50, Appendix G, or through performance of an applicable EMA, which is applicable to the reactor vessel plate component made from Heat C2779-1. The staff reviewed amended LRA Section A.2.1.3, consistent with 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. The SRP-LR also states that Table 4.2-1 of the SRP-LR contains examples of acceptable UFSAR supplement information for this TLAA and the reviewer verifies that the applicant has provided a UFSAR supplement with information equivalent to that in SRP-LR Table 4.2-1.

The staff finds the amended UFSAR supplement to be acceptable because it adequately summarizes how the USE TLAA has been evaluated to be in compliance with the requirements for USE in 10 CFR Part 50, Appendix G.

Based on its review of the amended UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.2.3.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of the USE of the reactor vessel materials, 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 provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the USE of the reactor vessel materials 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 Reactor Vessel Circumferential Weld Inspection Relief

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the TLAA for inspection relief for the RV circumferential welds. The RV was fabricated by Chicago Bridge and Iron (CB&I). ASME Code Section XI, Table IWB-2500-1, Examination Category B-A requires periodic volumetric examinations of the RV circumferential welds. As addressed in an NRC letter dated April 11, 2001, the applicant was granted inspection relief for the circumferential welds for the remaining period of the current operating license (32 EFPY). The basis of the staff’s approval for the inspection relief request was that the conditional probability of failure (CPF) for the applicant’s circumferential welds are bounded by staff-accepted CPF values for RV circumferential welds through the end of the current license period. These staff-accepted CPF values are described in the staff's SE (July 28, 1998) regarding BWRVIP-05, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations." The staff's approval for the inspection relief request was also based on the guidance in Generic Letter (GL) 98-05, which addresses the acceptance criteria for inspection relief for the circumferential welds, consistent with the staff's SE for BWRVIP-05.

LRA Section 4.2.4 provides the mean ART of the applicant's limiting circumferential welds, which is defined as "Initial RT_{NDT} + ΔRT_{NDT}." The mean ART of the applicant's welds was compared with the limiting-case mean ART for the CB&I RV circumferential welds that the staff determined for 64 EFPY in its SE for BWRVIP-05. The mean ART (-8 °F) of the applicant's circumferential welds at the end of the period of extended operation (54 EFPY) is significantly less than the staff-determined mean ART value (70.6 °F) for the limiting-case circumferential welds (64 EFPY). Since the ART value of the applicant's circumferential welds is bounded by the staff's assessment, the applicant concluded that the CPF for the applicant's circumferential welds remains below the limiting-case CPF.

In addition, the applicant stated that the procedures and training to minimize the potential for RV cold over-pressurization have been implemented. The applicant stated that it will request relief from the requirement to perform volumetric examinations of the RV circumferential welds, in accordance with 10 CFR 50.55a. The applicant initially dispositioned this TLAA in the LRA in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for the RV circumferential weld inspection relief has been projected to the end of the period of extended operation.

4.2.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the RV circumferential weld inspection relief and the corresponding disposition of 10 CFR 54.21(c)(1)(ii) consistent with SRP-LR Section 4.2.3.1.4, which states that the staff verifies that the applicant has identified that, should the inspection relief be desired for the period of extended operation, an application will be made under 10 CFR 50.55a(a)(3) prior to entering the period of extended operation.

In its review, the staff has verified all of the input parameters (copper and nickel content, unirradiated RT_{NDT}, neutron fluence) used for the probability of failure calculation listed in LRA Table 4.2-3, including the additional material with neutron fluence exceeding $1x10^{17}$ n/cm^2 for 54 EFPY. The staff noted that the applicant's TLAA has been projected to the end of the period of extended operation to support the relief from the ASME Code Section XI inservice inspection of circumferential welds. The applicant's alternative to the weld inspection is based on the staff's SE (July 28, 1998) regarding the BWRVIP-05 report. The staff's SE indicates that BWR applicants may request relief from inservice inspection requirements of 10 CFR 50.55a(g) for volumetric examination of RV circumferential welds by demonstrating the following items: at the expiration of their license, the circumferential welds satisfy the limiting CPF for circumferential welds specified in the staff's evaluation, and that the applicant has implemented operator training and established procedures to limit the frequency of cold over-pressure events.

The first acceptance criterion for the inspection relief is addressed in LRA Table 4.2-3 where the applicant confirmed that the mean ART value (-8 °F) of the applicant's limiting circumferential welds for the period of extended operation is less than the 64-EFPY ART value (70.6 °F) that the staff determined for the limiting-case circumferential weld of the CB&I RV. The staff found that the applicant's CPF analysis is acceptable because the mean ART values of RV circumferential welds govern the CPF values for the welds and that the applicant's analysis confirmed that the mean ART value of the applicant's circumferential welds is significantly less than the staff-determined mean ART value of the limiting-case circumferential welds for CB&I RVs. Hence, the CPF value for GGNS would be lower than the staff accepted generic CB&I value.

For the second acceptance criterion for the inspection relief, LRA Section 4.2.4 indicates that the applicant has implemented the procedures and training to minimize the potential for RV cold over-pressure events. In its review, the staff found that the continued implementation of operator training and establishment of procedures to limit the frequency of cold overpressure events meets the second acceptance criterion described in the staff's SE for BWRVIP-05.

However, the staff identified an issue with the applicant's disposition of this TLAA. SRP-LR Section 4.2.3.1.4 states that if the applicant indicates that relief from circumferential weld examination will be made under 10 CFR 50.55a(a)(3), the applicant will manage this TLAA in accordance with 10 CFR 54.21(c)(1)(iii). In contrast, the applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii), inconsistent with the SRP-LR. By letter dated October 17, 2012, the staff issued RAI 4.2.4-1, requesting the applicant explain why the TLAA for the circumferential weld inspection relief is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii) or revise the TLAA disposition to be in accordance with 10 CFR 54.21(c)(1)(iii).

In its response dated November 15, 2012, applicant amended its disposition of the TLAA to 10 CFR 54.21(c)(iii). In accordance with 10 CFR 54.21(c)(iii), the licensee affirmed that the effects of aging from neutron irradiation embrittlement of the RV circumferential welds will be adequately managed for the period of extended operation. The staff's concern described in RAI 4.2.4-1 is resolved.

As previously discussed, the applicant's September 1, 2015, response to RAI 4.2.1-2c, Part 5(a) confirmed that the staff approved the applicant's LAR to incorporate a single fluence method (MPM method) into the CLB. By its letter dated July 29, 2015 (response to RAI 4.2.1-2c, Part 5(b)), the applicant also revised LRA Section 4.2.4 to update the RV circumferential weld inspection relief analysis based on the updated fluence projections for 54 EFPY.

In its updated analysis, the applicant identified that circumferential weld AC is a new limiting circumferential weld in place of weld AB. The applicant also confirmed that the updated mean ART value (20 °F) of the new limiting weld is less than the 64-EFPY ART value (70.6 °F) that the staff determined for the limiting-case circumferential weld of the CB&I RV. In its review, the staff finds the updated analysis acceptable because the updated mean ART of the applicant's limiting circumferential weld is bounded by the staff's SE regarding the BWRVIP-05 report. The concern described in RAI 4.2.1-2c, Part 5(b) regarding the circumferential weld inspection relief analysis is resolved.

The staff finds the applicant's conclusion for this TLAA acceptable because the applicant's evaluation in LRA Section 4.2.4 confirms that the CPF values for the applicant's RV circumferential welds at 54 EFPY is bounded by the staff-accepted CPF values that are described in the SE (July 28, 1998) for BWRVIP-05. The applicant indicated that it will request relief from the requirement to perform volumetric examinations of the RPV circumferential welds, in accordance with 10 CFR 50.55a.

4.2.4.3 UFSAR Supplement

LRA Section A.2.1.4, as amended by letter dated November 15, 2012, provides the UFSAR supplement summarizing the TLAA for relief from RV circumferential weld examination. The staff reviewed LRA Section A.2.1.4, consistent with 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.

The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii), consistent with the SRP-LR that indicates that if the applicant will ask for relief from circumferential weld examination under 10 CFR 50.55a(a)(3), the applicant will manage this TLAA in accordance with 10 CFR 54.21(c)(1)(iii).

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address the TLAA for the relief from the RV circumferential weld inspection, 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 provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the RV circumferential weld 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).

4.2.5 Reactor Vessel Axial Weld Failure Probability

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.5 describes the applicant's TLAA for the RV axial weld failure probability for the period of extended operation. The staff's SE (October 18, 2001) for BWRVIP-74, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," evaluates the failure frequency of BWR RV axial welds. The staff's SE for BWRVIP-74 also indicates that a mean ART of 114 °F closely matches a failure frequency threshold of 5.0×10^{-6} per reactor-year that determines the acceptability of the RV failure frequency for the first 40 years of reactor operation. In addition, the staff's SE regarding BWRVIP-74 indicates that an acceptable method for performing this analysis is to demonstrate that the mean ART for 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 staff's SE for BWRVIP-74.

The mean ART for the applicant's limiting axial weld at 54 EFPY is projected to be -19 °F, which is significantly less than the acceptable mean ART value (114 °F) described in the staff's SE for BWRVIP-74. Therefore, the RV failure probability due to the failure of the applicant's limiting axial weld is well below the acceptable limit of 5.0×10^{-6} per reactor-year. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the neutron embrittlement of the RV axial welds has been projected to the end of the period of extended operation.

4.2.5.2 *Staff Evaluation*

The staff reviewed the applicant's TLAA for the RV axial weld failure probability and the corresponding disposition of 10 CFR 54.21(c)(1)(ii) consistent with SRP-LR Section 4.2.3.1.5. The SRP-LR states that the applicant should provide (a) a comparison of the neutron fluence, initial RT_{NDT}, chemistry factor, ΔRT_{NDT}, and mean RT_{NDT} (i.e., mean ART) of the limiting axial weld at the end of the license renewal period to the reference case in the BWRVIP and staff analyses; and (b) an estimate of conditional failure probability of the RV at the end of the license renewal term based on the comparison of the mean RT_{NDT} for the limiting axial welds and the reference case. The SRP-LR also states that the staff should ensure that the applicant's plant is bounded by the BWRVIP-05 analysis, or that the applicant has committed to a program to monitor axial weld embrittlement.

In its review, the staff has verified all of the input parameters (copper and nickel content, unirradiated RT_{NDT}, neutron fluence) used for the probability of failure calculation listed in LRA Table 4.2-4, including those for the additional materials with neutron fluence exceeding $1x10^{17}$ n/cm^2 for 54 EFPY. The staff noted that LRA Table 4.2-4 lists the mean ART (-19 °F) of the applicant's limiting axial weld for 54 EFPY to be compared with the acceptable mean ART value (114 °F), which is specified in the staff's SE for BWRVIP-74 and closely matches the acceptable failure frequency limit of $5.0x10^{-6}$ per reactor-year. The staff finds that the applicant's analysis is acceptable because the applicant confirmed that the mean ART of its liming axial weld is less than the acceptable mean ART value (114 °F) specified in the staff's SE for BWRVIP-74, indicating that the applicant's limiting case is bounded by the acceptable analysis in BWRVIP-74, consistent with the review procedures in the SRP-LR.

As previously discussed, the applicant's September 1, 2015, response to RAI 4.2.1-2c, Part 5(a) confirmed that the staff approved the applicant's LAR to incorporate a single fluence method (MPM method) into the CLB. By its letter dated July 29, 2015 (response to RAI 4.2.1-2c, Part 5(b)), the applicant also revised LRA Section 4.2.5 to update the RV axial weld failure probability analysis based on the updated fluence projections for 54 EFPY.

In its updated analysis, the applicant confirmed that the updated mean ART (-20 °F) of the applicant's limiting axial weld (Heat Number 5P6214B/0331 Tandem) for 54 EFPY is slightly lower than the previously determined mean ART (-19 °F) due to the reduction in peak fluence from $4.44x10^{18}$ to $4.02x10^{18}$ (energy greater than 1 MeV). In its review, the staff finds the updated analysis acceptable because the updated mean ART of the applicant's limiting axial weld is bounded by the acceptable mean ART value (114 °F), which is specified in the staff's SE for BWRVIP-74. In addition, the staff confirmed that the use of the credible chemistry factor from the integrated surveillance program would increase the mean ART value of the limiting axial weld by 12 °F but would not change the conclusion of this evaluation. The concern described in RAI 4.2.1-2c, Part 5(b) regarding the axial weld failure probability analysis is resolved.

Based on its review, the staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis for the neutron embrittlement of the RV axial welds has been projected to the end of the period of extended operation and confirmed that the level of the neutron embrittlement of the axial welds is bounded by the bounding-case neutron embrittlement analysis that is addressed in the staff's SE for BWRVIP-74. Therefore, the applicant's TLAA meets the acceptance criteria in SRP-LR Section 4.2.2.1.5 by confirming that the failure frequency of the RV for 54 EFPY due to the failure of axial welds is less than the failure frequency limit ($5.0x10^{-6}$ per reactor-year) specified in the SRP-LR.

4.2.5.3 *UFSAR Supplement*

LRA Section A.2.1.5 provides the UFSAR supplement summarizing the TLAA for the RV axial weld failure probability. The staff reviewed LRA Section A.2.1.5 consistent with 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 it meets the acceptance criteria in SRP-LR Section 4.2.3.2 and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address the TLAA for the RV axial weld failure probability.

4.2.5.4 *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)(ii), that the analysis for the RV axial weld failure frequency has 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 Reactor Pressure Vessel Core Reflood Thermal Shock Analysis

4.2.6.1 *Summary of Technical Information in the Application*

LRA Section 4.2.6 contains the applicant's TLAA for the RV core reflood thermal shock. Generic Electric Report NEDO-10029 addresses a RV core reflood thermal shock analysis and the analysis is relevant for the applicant for 40 years of the current license term as referenced in UFSAR, Section 5.3. In addition, the applicant cited a more recent analysis, which provides an evaluation of the core reflood thermal shock during loss-of-coolant accident (LOCA) event for a BWR-6 RV design: "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Fifth International Conference on Structural Mechanics on Reactor Technology, Berlin, Germany, August 1979, by S. Ranganath.

The more recent analysis indicates that when the peak stress intensity occurs at approximately 300 seconds after the LOCA, the temperature inside the vessel wall is approximately 400°F. The maximum ART value calculated for the applicant's RV beltline material is 53°F. Using the equation for fracture toughness (K_{IC}) presented in ASME Code, Section XI, Appendix A, and the applicant's maximum ART value for 54 EFPY, the applicant's limiting vessel material reaches USE at approximately 158°F. The 400°F temperature predicted for the thermal shock event at the time of peak stress intensity remains well above the 158°F value, at which the material would transition to the upper shelf. The analysis indicated that if the material was exhibiting upper-shelf behavior during the peak stress event, the vessel would be adequately protected. Therefore, the recent analysis projected the TLAA through the period of extended operation.

The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the RV core reflood thermal shock analysis has been projected to the end of the period of the extended operation.

4.2.6.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the RV core reflood thermal shock 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. The SRP-LR states that the staff reviews the revised analyses to verify that their period of evaluation is extended, such that they are valid for the period of extended operation (e.g., 60 years).

In its review, the staff noted that the LRA includes only a brief evaluation based on ART values and temperatures to demonstrate that the Ranganath analysis is bounding for the GGNS RV core reflood thermal shock analysis. The staff also noted that the LRA did not provide sufficient information for the staff to confirm the applicant's claim in the LRA. In addition, the staff requested clarification as to why the LRA does not identify the following items as a TLAA: (1) reflood thermal shock analysis of the RV core shroud and (2) growth of the core shroud stress-corrosion cracking (SCC) indication.

By letter dated June 5, 2012, the staff issued RAI 4.2.6-1 requesting that the applicant provide the following information and calculations to confirm that the applicant's RV materials are bounded by the analysis in the Ranganath paper as referenced in the LRA: (a.1) additional supporting information and calculations, including the projected fracture toughness values of the RV materials in comparison to the acceptable RV fracture toughness values for the postulated event, (a.2) confirmation as to whether the applicant's bounding-case analysis in LRA Section 4.2.6 includes all the relevant RV materials, the fast fluence values of which are projected to exceed 1×10^{17} n/cm^2 during the period of extended operation, not omitting any newly identified limiting material or extended beltline material (e.g., not omitting the relevant materials addressed in LRA Table 4.2-2), and (a.3) justification for why the applicant's RV is sufficiently similar to the RV analyzed in the paper for comparison.

In its response dated July 3, 2012, the applicant stated that the fracture toughness values are temperature dependent for any given material, and as shown in LRA Section 4.2.6, the plant-specific temperature at 1/4T depth into the vessel wall was determined to be 400°F at 300 seconds (with the peak stress) into the thermal shock event. The applicant also indicated that using the highest ART (53°F) for 54 EFPY, the RV materials are projected to have a fracture toughness (K_{IC}) of 200 ksi√in at approximately 158°F based on the fracture toughness equation in ASME Code Section XI, Appendix A. The applicant further indicated that since this temperature (158°F for 200 ksi√in) is significantly lower than 400°F, it is assured that the fracture toughness of the beltline materials remains at sufficiently high levels during the reflood thermal shock event. In addition, the applicant indicated that Figure 5 of the Ranganath paper demonstrates that at 300 seconds into the thermal shock event and 1/4T depth into the vessel wall, the maximum applied stress intensity factor (103 ksi√in) occurs and the maximum stress intensity factor during the thermal shock event is less than 200 ksi√in (i.e., the fracture toughness of the RV at 158°F based on the highest ART for 54 EFPY). The applicant stated that therefore, there is sufficient margin to prevent fracture due to reflood thermal shock.

The applicant addressed the request regarding the consideration of all the relevant RV materials and the bounding-case analysis as follows. The applicant stated that the maximum ART value (53°F) provided in LRA Section 4.2.6 is for the limiting material considering all relevant materials evaluated in LRA Table 4.2.2. The applicant also stated that this includes all materials that are exposed to fast fluence values in excess of 1×10^{17} n/cm^2. The applicant further stated that the input parameters to the applicant's analysis for this TLAA, such as vessel size and vessel thickness are similar to the input parameters considered in the Ranganath evaluation while the neutron fluence for the GGNS RV is less than the fluence used in the Ranganath evaluation.

In addition, the applicant stated that there is no reflood thermal shock analysis of the RV core shroud. The applicant stated that the reflood thermal shock analysis addressed in LRA Section 4.2.6 and the subsequent Ranganath evaluation applies to the RV, and potential effects on the SCC indication have not been evaluated for a reflood thermal shock event since no reflood thermal shock analysis exists for the applicant's RV core shroud.

Regarding the consideration of potential crack growth due to SCC, the applicant stated in its response that the indication found in the shroud circumferential weld was evaluated following discovery in 2005. The applicant indicated that the evaluation determined an acceptable inspection frequency and did not qualify the affected weld for service to the end of the 40-year operating term. The applicant stated that the flaw was found to be acceptable for service until the next inspection and, therefore, the crack growth does not meet the 10 CFR 54.3 definition of a TLAA. The applicant stated that potential SCC crack growth in the core shroud is monitored by the ISI Program described in LRA Section B.1.23.

In its review, the staff found the applicant's response acceptable because (a) the fracture toughness of the limiting RV material projected for 54 EFPY is adequate at 400°F such that the limiting-case fracture toughness of the RV is significantly greater than the maximum applied stress intensity factor (103 ksi√in) at the 1/4T location during the core reflood event, (b) the analysis includes all the relevant materials of the RV, and (c) the applicant clarified that no reflood thermal shock analysis exists for the applicant's RV core shroud such that a reflood thermal shock analysis is not a TLAA for the applicant's core shroud. The staff's concern described in RAI 4.2.6-1 is resolved.

As previously discussed, the applicant's September 1, 2015, response to RAI 4.2.1-2c, Part 5(a) confirmed that the staff approved the applicant's LAR to incorporate a single fluence method (MPM method) into the CLB. By its letter dated July 29, 2015 (response to RAI 4.2.1-2c, Part 5(b)), the applicant also revised LRA Section 4.2.6 to update the RV core reflood thermal shock analysis based on the updated fluence projections for 54 EFPY.

In its updated analysis, the applicant confirmed that the updated maximum ART value calculated for the applicant's RV beltline material is 51 °F, which is slightly less than the previously determined maximum ART value (53 °F). In its review, the staff finds the updated analysis acceptable because the updated maximum ART value, which is less than the previously determined one, does not affect the applicant's previous conclusion and staff's acceptance basis regarding the RV core reflood thermal shock analysis. The concern described in RAI 4.2.1-2c, Part 5(b) regarding the RV core reflood thermal shock analysis is resolved.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis for the RV core reflood thermal shock has been projected to the end of the period of extended operation. The LRA, and applicant's response to RAI 4.2.6-1, confirm that the fracture toughness of the limiting RV material at 54 EFPY is greater than the maximum applied stress intensity factor analyzed in the bound-case analysis for the RV core reflood shock. Therefore, the staff finds the applicant's TLAA is adequate for the period of extended operation.

4.2.6.3 UFSAR Supplement

LRA Section A.2.1.6, as amended by the July 29, 2015 letter, provides the UFSAR supplement summarizing the applicant's TLAA for the RV core reflood thermal shock analysis. The staff reviewed LRA Section A.2.1.6, consistent with 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 concludes that the information in the UFSAR supplement is an adequate summary description of the program, 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 provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis for RV core reflood thermal shock has been projected to the end of the period of extended operation. The staff also concludes that the UFSAR contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

4.3.1 Class 1 Fatigue

LRA Section 4.3.1 describes the applicant's Class 1 fatigue analyses. The LRA states that Class 1 components and systems that have fatigue analyses include the RV, the RVI, and Class 1 piping. These analyses were performed for the design of Class 1 components in accordance with their design requirements. The LRA also states that design cyclic loadings and thermal conditions for Class 1 components are defined by the applicable design specifications for each component, and the original design specifications provided the initial set of transients used in the design of the components. The Fatigue Monitoring Program tracks and evaluates transient cycles and requires corrective actions if limits are approached and ensures that the number of occurrences of each transient cycle that the plant experiences remain within the allowable numbers of cycles.

LRA Table 4.3-1 provides the numbers of cycles accrued to date and the projected number of accrued cycles expected at the end of 60 years of operation. The LRA states that the projected values through the period of extended operation were based on the rate of occurrence for the previous 10 years.

Staff Evaluation

The staff reviewed the applicant's projected and analyzed transient cycles in LRA Table 4.3-1 associated with its Class 1 fatigue analyses. The staff reviewed the list of transients used in the existing CUF analyses for the current operating term and the associated number of occurrences to assess the expected margin to the design cycle limits at the end of the period of extended operation. The staff also reviewed the relevant design basis information and CLB information (including applicable cycle-counting requirements in the TS).

The staff notes that the applicant will manage all of the Class 1 fatigue TLAAs using the Fatigue Monitoring Program, such that the projected transient cycle values provided in LRA Table 4.3-1 are for information purposes only, since the AMP will ensure that appropriate corrective actions are taken to ensure that counts for individual transients do not exceed their limits.

The staff reviewed LRA Section 4.3.1 and noted that the applicant did not explain why the operational data from 1985 to 1999 were not taken into account for the 60-year projections. In addition, the applicant did not justify why the data between 1999 and 2010 used in the 60-year projections were conservative. By letter dated May 24, 2012, the staff issued RAI 4.3-1, requesting the applicant to justify why the operational data between initial plant operation in 1985 to 1999 was not considered and to justify why using the data between 1999 and 2010 is a conservative approach to project to 60 years of plant operation.

In its response dated June 21, 2012, the applicant stated that plant operating data from the 10.4-year period on which LRA Table 4.3-1 is based is considered a more accurate representation of future transient cycle occurrence rate than data extending back to initial plant startup. The applicant explained that startup testing and initial equipment operation caused a high frequency of occurrences during 1985 to 1999 and incorporating lessons learned from operating experience has resulted in improved plant performance and a consequently lower rate of transient occurrence. In addition, the applicant stated the use of data from 1999 and 2010 is a conservative approach for projections to 60 years of plant operation since the plant was on 18-month operating cycles during this time but will be operating on a 24-month fuel cycle in the future. The staff noted longer operating times between refueling cycles equates to fewer occurrences of normal and test transients. The applicant stated that the projections were not used to reduce cycles assumed for any analysis, including the EAF screening, does not replace the original transient cycle limits, and is not used to satisfy 10 CFR 54.21(c)(1)(ii). Furthermore, actions will be taken based on actual accrued cycles regardless of projected values.

The staff finds it reasonable that the operating data early in plant life were not used in the 60-year projections because the recent operating data is an accurate representation of how the applicant operates its plant based on lessons learned and operating experience. However, regardless of the projections the applicant provided in the LRA, the applicant’s Fatigue Monitoring Program is tracking the number of cycle occurrences or calculating cumulative fatigue usage to ensure that corrective actions are taken before a design cycle limit or the design limit on fatigue usage is exceeded. The staff noted that these projections provide an early indication of whether design cycle limits may be exceeded and that the Fatigue Monitoring Program provides for management of fatigue.

The staff finds the applicant’s response to RAI 4.3-1 acceptable because the applicant explained why early operating data for transients were not included, explained that these cycle projections were not used to provide validation or update fatigue analyses, and stated that the Fatigue Monitoring Program will ensure that corrective actions are taken before a design cycle limit or design limit of fatigue usage is exceeded during the period of extended operation. The staff’s concern described in RAI 4.3-1 is resolved.

LRA Table 4.3-1 states that the “Design Hydro” transient originally was designed to 40 cycles of pressurization with a pressure of 1,250 psig. In addition, since the test was performed at less than 1,050 psig, the number of allowable cycles has been recalculated as 50 cycles. However, the staff noted that the UFSAR still indicates that the allowable number of cycles for this transient is 40 cycles. The applicant did not explain how the number of allowable cycles for the “Design Hydro” transient was recalculated to 50 cycles, what limits are being used in the Fatigue Monitoring Program, and why the information between the LRA and the UFSAR is not consistent. By letter dated May 24, 2012, the staff issued RAI 4.3-2 requesting the applicant to clarify the discrepancy in information associated with the “Design Hydro” transient in the LRA and UFSAR and to clarify the limit that the Fatigue Monitoring Program will be managing. In addition, the applicant was requested to identify all other transients in which the number of allowable cycles in the LRA is not consistent with the CLB (e.g., TS and UFSAR) and to justify any differences.

In its response dated June 21, 2012, the applicant stated that the “Design Hydro” transient is specified as having a maximum pressure of 1,250 psig for design purposes. However, an actual “Design Hydro” transient reaches a peak pressure of only 1,025 psig. The applicant further stated that by conservatively assuming 1,050 psig for every occurrence of this transient, the less severe nature of the actual transient resulted in an increase in the allowed number of cycles while ensuring the design basis usage for the worst case location would remain the same. The staff finds it reasonable that a decrease in pressure for a transient results in a lower value of stress that the component experiences. Consistent with the trend of the ASME Code design fatigue curves, a lower value of stress results in an increase in the number of allowable cycles. The applicant also explained that UFSAR Table 3.9-35 contains a footnote indicating that the cycles listed are the (original) design transient limits and that the current fatigue operating cycle information is located in a site-specific mechanical standard; thus, no UFSAR change is necessary.

The applicant stated that LRA Table 4.3-1 lists the analyzed numbers of cycles. Further, a comparison of this table to the UFSAR and TS revealed that the LRA values are equivalent to the values in the UFSAR and TS except for the “Design Hydro” transient and the single safety relief valve (SRV) actuation and shutdown transients. The staff noted that the LRA values for the single SRV actuation and shutdown transients are less than the design cycle limits specified in the UFSAR. The staff finds this acceptable and conservative because the Fatigue Monitoring Program is monitoring these two transients to a lower cycle limit than the design cycle limits specified in the UFSAR, which ensures that the design limit for these two transients will not be exceeded.

The staff finds the applicant’s response to RAI 4.3-2 acceptable because the applicant (1) clarified how the cycle limit on the “Design Hydro” transient was increased, (2) confirmed that its UFSAR already provides a reference to this updated cycle limit, and (3) confirmed that there are no other differences in cycle limits between the LRA and the UFSAR, except as justified above. The staff’s concern described in RAI 4.3-2 is resolved.

The staff noted in LRA Table 4.3-1 that the “Loss of Feedpumps” transient may exceed its design cycle limit of 10 during the period of extended operation. The applicant did not explain how exceeding the design cycle limit for this transient during the period of extended operation will impact fatigue TLAAs and why exceeding the design limit for this transient would affect only the RV FW nozzle. By letter dated May 24, 2012, the staff issued RAI 4.3-3 requesting the applicant to identify all components that included the “Loss of Feedpumps” transient in its fatigue analysis and discuss how exceeding the design cycle limit for this transient will affect these fatigue TLAAs. In addition, the staff requested the applicant to justify how the Fatigue Monitoring Program will ensure that fatigue usage remains within the allowable limit given that one of the design transients used in the fatigue analysis is expected to exceed the design limit during the period of extended operation if stress-based fatigue is not used as the monitoring method.

In its response dated June 21, 2012, the applicant stated that the loss of FW pumps transient is a part of the design basis for its plant and, therefore, was included for all Class 1 components that have an associated fatigue analysis. Based on the design basis fatigue analyses, the cycle-based fatigue monitoring method was chosen assuming that design basis transient severity will produce the design basis fatigue usage if the design basis number of cycles occurs. The staff noted that this method also accounts for more or fewer occurrences of a particular transient by calculating the cumulative fatigue usage incurred based on the number of transients that actually occur regardless of the number of occurrences assumed in the design analyses.

The applicant clarified that for the period of extended operation, stress-based fatigue monitoring is planned only for the FW nozzles; however, if a cycle-based fatigue monitoring location approaches its allowable usage, then stress-based fatigue monitoring would be an option. The applicant explained that its program will automatically account for the incremental fatigue usage for each "Loss of Feedpumps" transient, even if the design basis number of transients is exceeded. The staff's review of the applicant's Fatigue Monitoring Program and more specifically cycle-based fatigue monitoring and stress-based fatigue monitoring is documented in SER Section 3.0.3.1.18.

The staff finds the applicant's response to RAI 4.3-3 acceptable because the applicant clarified that all Class 1 components that have an associated fatigue analysis are affected by the loss of feedpumps transient. The applicant also justified that, by using cycle-based fatigue monitoring, it can periodically calculate cumulative fatigue usage, which is based on design severity and design fatigue usage contribution per transient occurrence, to ensure the design limit on fatigue usage is not exceeded even if a design cycle limit is exceeded. Further, the applicant's Fatigue Monitoring Program includes an option to use stress-based fatigue monitoring, which provides more detailed monitoring to manage accumulated fatigue usage. The staff's concern described in RAI 4.3-3 is resolved.

LRA Table 4.3-1 indicates that the 60-year projections for several transients are expected to exceed their associated design allowable limit during the period of extended operation. LRA Section 4.3.1 discusses subsequent projections that will refine the estimate of the numbers of cycles expected through 60 years of operation. However, the applicant did not identify the locations or fatigue analyses that will be affected by these design transients and it is not clear to the staff how often the applicant will perform these subsequent cycle projections. By letter dated May 24, 2012, the staff issued RAI 4.3-4 requesting the applicant to identify the locations that will be affected by transients that have 60-year projected cycles that exceed their associated design cycle limit during the period of extended operation; to clarify how often these subsequent cycle projections will be performed; and whether they are part of the Fatigue Monitoring Program.

In its response dated June 21, 2012, the applicant clarified that the term "locations" in LRA Section 4.3.1 that was referenced in the staff's RAI was meant to refer to transients and not to plant locations. The applicant revised LRA Section 4.3.1 to provide this clarification between the terms "locations" and "transients." The applicant also clarified that when an allowable value for cycles is approached, the Fatigue Monitoring Program will initiate corrective action that will require identifying the plant locations affected by the specific transient. The staff finds the applicant's revisions to LRA Section 4.3.1 acceptable because it clarified that the applicant's program is managing the transients used as assumptions into the fatigue analyses and that corrective actions will include identification of the specific plant locations that may be affected if an allowable cycle limit is approached.

The applicant stated that the projections to 60 years are included as part of the periodic update completed by the Fatigue Monitoring Program once every two operating fuel cycles. The projections in these periodic updates are not necessary to adequately manage the effects of metal fatigue during the period of extended operation and are considered as inputs to optimize resource utilization when planning future activities for the program. These projections are used for information only. The applicant stated that the Fatigue Monitoring Program will ensure that fatigue usage remains within allowable limits, independent of the 60-year projections. The staff finds it acceptable that the applicant uses these periodic refinements for the 60-year projections as information for the purposes of resource utilization and planning future activities because the Fatigue Monitoring Program periodically ensures that the allowable cycle limit and allowable design limit on fatigue usage is not exceeded based on the actual occurrence of transient cycles. The staff's review of the Fatigue Monitoring Program and its ability to manage metal fatigue during the period of extended operation is documented in SER Section 3.0.3.1.18.

The staff finds the applicant's response to RAI 4.3-4 acceptable because the applicant revised LRA Section 4.3.1 to clarify the terms "locations" and "transients," the applicant explained how it will use subsequent cycle projections as information for resource utilization and planning future activities, and the Fatigue Monitoring Program periodically ensures corrective actions are taken before an allowable cycle limit or design limit on fatigue usage is exceeded during the period of extended operation. The staff's concern described in RAI 4.3-4 is resolved.

UFSAR Table 3.9-1 indicates that there are 400 design cycles for the "control rod pattern change" transient and UFSAR Table 3.9-35 indicates that there are 80 step-change cycles for the "loss of feedwater heaters" transient. The staff noted that these transients were not included in LRA Table 4.3-1; therefore, it is not clear whether they have been used as inputs into the TLAAs discussed in LRA Section 4.3. By letter dated May 24, 2012, the staff issued RAI 4.3-6 requesting the applicant to identify the TLAAs in LRA Section 4 that used these transients as an input and confirm that these transients were monitored since initial plant startup. In addition, based on disposition of these identified TLAAs, the applicant was requested to clarify whether these transients are currently included in the Fatigue Monitoring Program or to provide the accumulated number and projected number of occurrences for each transient in LRA Tables 4.3-1.

In its response dated June 21, 2012, the applicant stated each of the Class 1 metal fatigue TLAA evaluated in LRA Section 4.3 used the "loss of feedwater heaters" transient as an input. The applicant explained that the 80 step-change cycles for the "loss of feedwater heaters" transient result from the summation of two transients that have been monitored since plant startup. These two transients are the turbine bypass (10 cycles) and partial FW heater bypass (70 cycles). The applicant confirmed that the Fatigue Monitoring Program tracks the turbine bypass and partial FW heater bypass transients. It stated that the "control rod pattern change" transient was considered for the fatigue analyses of the FW nozzle and piping system and has a small effect on pressure and temperature. This transient has not been tracked since its effect on fatigue usage was determined to be insignificant. The staff's evaluation associated with the Fatigue Monitoring Program not monitoring the "control rod pattern change" transient is documented in SER Section 3.0.3.1.18, in which the staff found this transient does not need to be monitored. The applicant confirmed that none of the Class 1 metal fatigue TLAAs in LRA Section 4.3 are evaluated in accordance with 10 CFR 54.21(c)(1)(i) or 54.21(c)(1)(ii). Instead, the staff noted they were all evaluated in accordance with 10 CFR 54.21(c)(1)(iii).

The staff finds the applicant's response to RAI 4.3-6 acceptable because it clarified that the "loss of feedwater heaters" transient is the combination of the turbine bypass (10 cycles) and partial FW heater bypass (70 cycles) transients; the applicant confirmed that these transients have been monitored since plant startup and are included in the applicant's Fatigue Monitoring

Program for the period of extended operation, which will ensure corrective actions are taken if a cycle limit is approached. In its response, the applicant also justified not monitoring the “control rod pattern change” transient. The staff’s concern described in RAI 4.3-6 is resolved.

The staff’s review of the applicant’s Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue and environmentally-assisted fatigue (EAF) during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant’s Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

UFSAR Supplement

LRA Section A.2.2.1 provides the UFSAR supplement summarizing Class 1 metal fatigue. The staff reviewed LRA Section A.2.2.1 consistent with 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 TLAA.

Based on its UFSAR supplement review, 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 Class 1 fatigue analyses, as required by 10 CFR 54.21(d). Additional details of the staff’s evaluation for specific Class 1 fatigue analyses are documented below.

Conclusion

On the basis of its review, the staff concludes that the applicant provided an adequate description and acceptable basis for monitoring design transients and cycles and managing cumulative fatigue usage with its Fatigue Monitoring Program. The program ensures that corrective actions are taken before exceeding the design limit during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the monitoring bases of transients and design cycles, as required by 10 CFR 54.21(d).

4.3.1.1 Reactor Vessel

4.3.1.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1.1 describes the applicant’s TLAA for metal fatigue of the RV components. The LRA states that UFSAR Section 5.3.3.3 describes the RPV as being fabricated in accordance with ASME Code Section III, Class 1 requirements. In addition, the RPV fatigue analyses were performed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, its interpretations, and applicable requirements for Class A vessels as defined therein, as of the order date of December 1972. LRA Table 4.3-2 provides a list of the 40-year design CUFs for critical RV locations.

The applicant dispositioned the metal fatigue TLAA for RV components in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of aging due to fatigue on the RV will be adequately managed for the period of extended operation.

4.3.1.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA for metal fatigue of the RV components and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 GALL Report and included an assessment of the TLAA information against relevant design basis and CLB information.

The staff reviewed LRA Table 4.3-2 and noted that the CUF values for the RV components are less than 1.0. The staff noted that, while these CUF values are less than the design limit of 1.0, the applicant has proposed managing fatigue of these components with its Fatigue Monitoring Program to ensure that fatigue is managed and the design limits are not exceeded during the period of extended operation. The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that this program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the RV components analyzed in accordance with ASME Code Section III 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 in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.1.3 UFSAR Supplement

LRA Section A.2.2.1 provides the UFSAR supplement summarizing metal fatigue for the RV. The staff reviewed LRA Section A.2.2.1 consistent with 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 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 RV fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue for the RV 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).

4.3.1.2 Reactor Vessel Feedwater Nozzle

4.3.1.2.1 Summary of Technical Information in the Application

LRA Section 4.3.1.2 describes the applicant's TLAA for metal fatigue of the RV FW nozzle. The LRA states that, as described in UFSAR Section 5.3.3.1.4.5.1, the FW nozzle design includes features to eliminate thermal fatigue concerns identified in previous BWR FW nozzle designs. This included a second piston ring and triple thermal sleeves being incorporated into the design of the nozzle. The LRA also states that the analysis of the FW nozzle determined the fatigue usage from potential rapid cycling behind the thermal sleeves that is added to the fatigue usage based on monitored plant transients.

The applicant dispositioned the metal fatigue TLAA for the RV FW nozzle in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue for these nozzles will be adequately managed for the period of extended operation.

4.3.1.2.2 Staff Evaluation

The staff reviewed the applicant's TLAA for metal fatigue of the RV FW nozzles and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 GALL Report, and included an assessment of the TLAA information against relevant design basis and CLB information.

The staff noted that LRA Section A.2.2.1 states that the applicant implemented a plant modification before plant operation to eliminate concerns identified in previous BWR designs for the FW nozzle. Furthermore, the analysis for this modification included fatigue from potential rapid cycling behind the thermal sleeves; therefore, the FW nozzle analysis contains a location-specific rapid cycling fatigue usage that is added to the cycle-based fatigue usage. The LRA also states that the FW nozzle will be re-evaluated for EAF and will consider the effects of potential rapid cycling as necessary.

However, the staff noted that the LRA did not explain how the potential rapid cycling will be considered in the reanalysis and under what condition it is considered "necessary." In addition, LRA Section A.2.2.1 did not provide an adequate summary description of the activities for managing the effects of rapid cycling for the RV FW nozzle. By letter dated May 24, 2012, the staff issued RAI 4.3-10 requesting the applicant to provide additional information related to the incorporation of rapid cycling in the reanalysis of the FW nozzle and to revise LRA Section A.2.2.1 to provide an adequate summary description related to aging management of rapid cycling.

In its response dated June 21, 2012, the applicant stated that the reanalysis of the FW nozzle for consideration of the effects on fatigue of the reactor water environment EAF will consider the effects of rapid cycling based on thermal duty maps (i.e., flow rates and time spent at different FW and vessel temperatures). The applicant stated that plant operational data will be used in the analysis to account for actual historical operation and the effects of rapid cycling on the FW nozzle will be considered for any operating condition in which there is FW flow. In addition, the applicant revised LRA Section A.2.2.1 to provide a summary description of how it intends to manage rapid cycling and include it into the reanalysis for the FW nozzle.

The staff noted that the phenomena of rapid cycling of the FW nozzle is the result of small thermal amplitude and high frequency temperature changes caused by the mixing of hotter reactor coolant with colder incoming FW at the nozzle annulus that impinges on the FW nozzle wall, causing thermal cycling of the metal surface. Based on the circumstances that rapid cycling occurs at the FW nozzle and the applicant's resolution to GL 81-11 that addressed potential cracking at FW nozzle, the staff finds it appropriate that the applicant will consider rapid cycling based on actual historical operational data of reactor coolant and incoming FW temperatures to determine the accrued fatigue usage in the EAF reanalysis. In addition, the staff finds it appropriate that rapid cycling will be considered in the EAF reanalysis for any transient with operating condition in which there is FW flow to determine the contribution to fatigue usage from the mixing of hotter reactor coolant with colder incoming FW.

The staff finds the applicant's response to RAI 4.3-10 acceptable because (a) the applicant is considering transients (e.g., rapid cycling of the FW nozzle) that cause cyclic strains that are significant contributors to the fatigue usage consistent with GALL Report AMP X.M1, (b) the applicant's method for incorporating rapid cycle of the FW nozzle is appropriate, as described above, and (c) the applicant revised LRA Section A.2.2.1 to provide an adequate summary description for aging management of rapid cycling for the FW nozzle. The staff's concern described in RAI 4.3-10 is resolved.

The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the reactor FW nozzles analyzed in accordance with ASME Code Section III 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 in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.2.3 UFSAR Supplement

LRA Section A.2.2.1, as amended by letter dated June 21, 2012, provides the UFSAR supplement summarizing metal fatigue for the reactor FW nozzle. The staff reviewed LRA

Section A.2.2.1 consistent with 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 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 reactor FW nozzle fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue for the reactor FW nozzles 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).

4.3.1.3 Reactor Pressure Vessel Internals

4.3.1.3.1 Summary of Technical Information in the Application

LRA Section 4.3.1.3 describes the applicant’s TLAA for metal fatigue of RPV internals. The LRA states that the RPV internals consist of the core support structure and non-core support structure components. Furthermore, the core support structure components are ASME Code components; however, the ASME Code requirements do not apply to the non-core support structure components, but the methods of the ASME Code were used in their design. The LRA also states that the original analyses for the core support structure used the 1974 edition with addenda up to and including the Summer 1976 Addenda.

The applicant dispositioned the metal fatigue TLAA for RPV internals in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue for the RPV internals will be adequately managed for the period of extended operation.

4.3.1.3.2 Staff Evaluation

The staff reviewed the applicant’s TLAA for metal fatigue of the RPV internals and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 GALL Report and included an assessment of the TLAA information against relevant design basis and CLB information.

LRA Section 4.3.1.3 did not identify the transients that were used for the RPV internals; therefore, the staff cannot verify the adequacy of the disposition of the fatigue TLAA for the RPV internals in accordance with 10 CFR 54.21(c)(1)(iii). By letter dated May 24, 2012, the staff issued RAI 4.3-7 requesting the applicant to identify the transients and associated design cycles used for the RVI fatigue analyses and confirm that these transients are included in the Fatigue Monitoring Program.

In its response dated June 21, 2012, the applicant confirmed that the transients and associated design cycles used in the fatigue analysis of the RVI are the same as those used in the fatigue analysis of the RCS pressure boundary components. Furthermore, these transients and associated design cycles are listed in LRA Table 4.3-1 and are included in the Fatigue Monitoring Program. The staff noted that the applicant's Fatigue Monitoring Program monitors the transients listed in LRA Table 4.3-1, which are used as inputs into the fatigue analyses of the RCS pressure boundary components and RPV internals, to ensure that corrective actions are taken before a design cycle limit or the design limit on fatigue usage is exceeded.

The staff finds the applicant's response to RAI 4.3-7 acceptable because it confirmed that the transients used as inputs in the fatigue analyses of the RPV internals are already listed in LRA 4.3-1 and are monitored by the Fatigue Monitoring Program. The staff's concern described in RAI 4.3-7 is resolved.

The staff reviewed LRA Table 4.3-3 and noted that the CUF values for the RPV internals are less than 1.0. The staff noted that, while these CUF values are less than the design limit of 1.0, the applicant has proposed managing fatigue of these components with its Fatigue Monitoring Program to ensure that fatigue is managed and the design limits are not exceeded during the period of extended operation. The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the RPV internals analyzed for metal fatigue 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 in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.3.3 UFSAR Supplement

LRA Section A.2.2.1 provides the UFSAR supplement summarizing metal fatigue for the RPV internals. The staff reviewed LRA Section A.2.2.1 consistent 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 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 RPV internal fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.3.4 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 the effects of fatigue for the RPV internals 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).

4.3.1.4 Reactor Recirculation Pumps

4.3.1.4.1 Summary of Technical Information in the Application

LRA Section 4.3.1.4 describes the applicant's TLAA for metal fatigue of the reactor recirculation pumps. The LRA states that UFSAR Section 3.9.1.2.1.4 describes the Byron-Jackson recirculation pump fatigue analysis. This analysis for the reactor recirculation pump casing considered the RCS fatigue transients specified by GE, justified exempting portions of the casing from analysis and determined that the remaining locations met 1974 ASME Code Section III fatigue requirements.

The applicant dispositioned the metal fatigue TLAA for the reactor recirculation pumps in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue for reactor recirculation pumps will be adequately managed for the period of extended operation.

4.3.1.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for metal fatigue of the reactor recirculation pumps and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 GALL Report and included an assessment of the TLAA information against relevant design basis and CLB information.

LRA Section 4.3.1.4 states that the fatigue analysis for the Byron-Jackson reactor recirculation pump casing considered the transients specified by GE and this analysis justified exempting portions of the case from analysis. In addition, it also determined that the remaining locations met 1974 ASME Code Section III fatigue requirements. The staff noted that LRA Section 4.3.1.4 and UFSAR Section 3.9.1.2.1.4 did not provide information about the locations of the pump casing that were exempt from a fatigue analysis and the locations that met 1974 ASME Code Section III fatigue requirements. In addition, the applicant did not explain how the locations were determined to be exempt and whether the Fatigue Monitoring Program ensures that the assumptions associated with this determination will continue to remain valid during the period of extended operation.

By letter dated May 24, 2012, the staff issued RAI 4.3-11 requesting the applicant to provide additional information about the locations and the provision that permitted the fatigue requirement exemptions for the Byron-Jackson reactor recirculation pump casing. In addition, the applicant was requested to justify whether or not this exemption for a fatigue analysis needs to be identified as a TLAA and to explain how the exemptions will remain valid during the period of extended operation. The staff also requested information for the locations that met 1974 ASME Code Section III fatigue requirements and the locations in the pump cover that were later reanalyzed because of modifications to install shaft sleeves and modify the seal water heat exchanger.

In its response dated June 21, 2012, the applicant confirmed that the pump casing was exempt from fatigue analysis per ASME Code Section III NB-3222.4(d) and the only component in the pump cover assembly requiring analysis was the seal water heat exchanger. The staff noted that an analysis for cyclic service is not required if the six criteria specified in ASME Code Section III NB-3222.4(d) are met, which include conditions associated with atmospheric to service pressure cycle, normal service pressure fluctuation, temperature differences during startup and shutdown cycles and normal service, temperature difference in DM weld, and mechanical loads. The applicant stated that since this determination considered the assumed number of transients specified by GE, this evaluation for a fatigue analysis exemption is treated as a TLAA. By tracking cycles associated with the exemption against the allowable numbers of cycles with the Fatigue Monitoring Program, the applicant stated this will ensure that this exemption will remain valid during the period of extended operation.

The staff noted the transients specified by GE that were used in this exemption and the RCS are the same and are monitored by the applicant's Fatigue Monitoring Program; therefore, the staff finds it acceptable that the applicant is using this program to ensure that this exemption remains valid during the period of extended operation. In addition, the staff finds the applicant's approach to manage this exemption acceptable because the applicant provided an enhancement to its Fatigue Monitoring Program to ensure the validity of this exemption analysis during the period of extended operation. The staff's review of the Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18.

The applicant stated that the seal water heat exchanger on the pump cover in its original configuration was analyzed in 1980 using the 1974 ASME Code Section III fatigue requirements. The staff noted that, following modifications to install shaft sleeves and to modify the seal water heat exchanger, the CUF also was determined to be less than 1.0.

The staff finds the applicant's response to RAI 4.3-11 acceptable because it identified the components of the reactor recirculation pump that were subject to the exemption and to a fatigue analysis. Further, the applicant enhanced its Fatigue Monitoring Program to ensure that corrective actions are taken if the validity of the fatigue exemption is challenged during the period of extended operation, and the applicant's Fatigue Monitoring Program is managing those transients that are contributors to the CUF value for the shaft sleeves and modified seal water heat exchanger on the pump cover. The staff's concern described in RAI 4.3-11 is resolved.

The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

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 reactor recirculation pumps 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 in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.4.3 UFSAR Supplement

LRA Section A.2.2.1 provides the UFSAR supplement summarizing metal fatigue for the reactor recirculation pumps. The staff reviewed LRA Section A.2.2.1 consistent with 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 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 reactor recirculation pump fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.4.4 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 the effects of fatigue for the reactor recirculation pumps 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).

4.3.1.5 Control Rod Drives

4.3.1.5.1 Summary of Technical Information in the Application

LRA Section 4.3.1.5 describes the applicant's TLAA for metal fatigue of the CRDs. The LRA states that the Class 1 portions of the CRDs were analyzed for fatigue and that the CUF values are low and the tracking of cycles under the Fatigue Monitoring Program ensures the fatigue on these components remains acceptable. LRA Table 4.3-4 provides the CUF values for the Class 1 CRD components.

The applicant dispositioned the metal fatigue TLAA for the CRDs in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue for these components will be adequately managed for the period of extended operation.

4.3.1.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for metal fatigue of the CRDs and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 GALL Report and included an assessment of the TLAA information against relevant design basis and CLB information.

The staff reviewed LRA Table 4.3-4 and noted that the CUF values for the CRD components are significantly less than 1.0, with the highest being 0.2 for the lower piston tube threads. The staff noted that while these CUF values are low such that the design limit of 1.0 should not be exceeded, the applicant has proposed managing fatigue of these components with its Fatigue

Monitoring Program to ensure that fatigue is managed and the design limits are not exceeded during the period of extended operation. The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the CRD components 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 in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.5.3 UFSAR Supplement

LRA Section A.2.2.1 provides the UFSAR supplement summarizing metal fatigue for the reactor CRDs. The staff reviewed LRA Section A.2.2.1 consistent with 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 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 reactor CRD fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.5.4 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)(iii), that the effects of fatigue for the CRD 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).

4.3.1.6 Class 1 Piping

4.3.1.6.1 Summary of Technical Information in the Application

LRA Section 4.3.1.6 describes the applicant's TLAA for metal fatigue of the Class 1 piping. The LRA states that the components of the RCPB whose failure could cause a loss of reactor coolant at a rate in excess of the normal makeup system capability are ASME Code Section III Class 1 components. The LRA provided a table of Class 1 systems and the associated piping and instrumentation diagram for the LRA. The LRA also states that its ASME Code Class 1 piping specifications identified that the piping must be analyzed for the cycles identified on GE transient cycle drawings and a detailed fatigue analysis was generated to analyze multiple locations on each system within the ASME Class 1 boundary. LRA Table 4.3-5 provides the highest CUF value identified in the analyses for each system containing Class 1 piping and is from the analysis of record, which does not include the effects of reactor water environment EAF, which is evaluated in LRA Section 4.3.3. The Fatigue Monitoring Program will monitor the cycles actually incurred to ensure that action is taken if the actual cycles approach their analyzed numbers.

The applicant dispositioned the metal fatigue TLAA for Class 1 piping in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue for these components will be adequately managed for the period of extended operation.

4.3.1.6.2 Staff Evaluation

The staff reviewed the applicant's TLAA for metal fatigue of Class 1 piping and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 GALL Report and included an assessment of the TLAA information against relevant design basis and CLB information.

The staff noted that LRA Table 4.3-5 provides a CUF value of 0.4138 for the FW piping; however, LRA Table 4.3-6 provides a CUF value of 0.2228 for the FW piping. It is not clear to the staff why there is a discrepancy between the CUF values for the FW piping in the LRA tables and why the EAF evaluation used the lower CUF value of 0.2228, instead of 0.4138. The staff noted that if the environmental fatigue life correction factor (F_{en}) value provided in LRA Table 4.3-6 was used with the CUF value of 0.4138, the CUF_{en} exceeds the ASME Code limit of 1.0. In addition, it is not clear to the staff why the CUF value for the LPCS RV nozzle, HPCS RV nozzle, and RV nozzle-RHR are all the same. By letter dated May 24, 2012, the staff issued RAI 4.3-12 requesting the applicant to clarify these discrepancies for the FW piping and the LPCS RV nozzle, HPCS RV nozzle, and RV nozzle-RHR.

In its response dated June 21, 2012, the applicant clarified that the correct FW piping CUF value was determined to be 0.2228 and that LRA Table 4.3-5 has been revised with the correct value. With the revision to the LRA, the staff noted that the CUF values for the FW piping in LRA Tables 4.3-5 and 4.3-6 are consistent and the use of this CUF value in the EAF evaluation for the FW piping is appropriate. Based on the applicant's response, the staff noted that the CUF values for the LPCS RV nozzle, HPCS RV nozzle, and RV nozzle-RHR were evaluated by a common analysis during its original design; thus, the staff finds it reasonable that these nozzles would have the same CUF value of 0.564. The staff noted that this approach of using a bounding analysis to be representative of several components (e.g., the LPCS RV nozzle, HPCS RV nozzle, and RV nozzle-RHR) is typical during the original design of the plant because of the similarities of the components (e.g., material, stress and loading, effects from thermal and pressures transients).

The staff finds the applicant's response to RAI 4.3-12 acceptable because the applicant confirmed that the correct CUF value for the FW piping was used in the EAF evaluation and the applicant explained that the CUF values for the LPCS and HPCS RV nozzle and RV nozzle-RHR were evaluated by one analysis and thus share the same CUF value. The staff's concern described in RAI 4.3-12 is resolved.

The staff reviewed LRA Table 4.3-5 and noted that the CUF values for the Class 1 system components are less than 1.0. The staff noted that while these CUF values are less than the design limit of 1.0, the applicant has proposed managing fatigue of these components with its Fatigue Monitoring Program to ensure that fatigue is managed and the design limits are not exceeded during the period of extended operation. The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods is conservative and progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

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 Class 1 piping analyzed for metal fatigue 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 in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.6.3 UFSAR Supplement

LRA Section A.2.2.1 provides the UFSAR supplement summarizing metal fatigue for Class 1 piping. The staff reviewed LRA Section A.2.2.1 consistent with 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 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 reactor Class 1 piping fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.6.4 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 the effects of fatigue for 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).

4.3.2 Non-Class 1 Fatigue

4.3.2.1 Non-Class 1 Fatigue – Piping and In-Line Components

4.3.2.1.1 Summary of Technical Information in the Application

LRA Section 4.3.2.1.describes the applicant's non-Class 1 piping and in-line component fatigue analyses. The LRA states that the impact of thermal cycles on non-Class 1 components is addressed in the calculation of the allowable stress range. The design of ASME Code Section III Class 2 and 3 or ANSI B31.1 piping systems incorporates a stress range reduction factor for piping design for thermal stresses. In general, a stress range reduction factor of 1.0 in the stress analyses applies for up to 7,000 thermal cycles. The allowable stress range is reduced by the stress range reduction factor if the number of thermal cycles exceeds 7,000. For many plant systems, significant temperature cycles are coincident with plant heatups and cooldowns. In addition, there are other plant systems with transients that occur independently of plant heatups and cooldowns.

The applicant dispositioned the metal fatigue TLAA for non-Class 1 piping and in-line components in accordance with 10 CFR 54.21(c)(1)(i), that the non-Class 1 piping stress calculations remain valid for the period of extended operation.

4.3.2.1.2 Staff Evaluation

The staff reviewed the applicant's metal fatigue TLAA for non-Class 1 piping and in-line components and the corresponding disposition of 10 CFR 54.21(c)(1)(i) consistent with 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 the allowable limit for full thermal range transients will not be exceeded during the period of extended operation.

The applicant stated that for many plant systems, significant temperature cycles are coincident with plant heatups and cooldowns. The staff noted that these same plant systems can also experience significant temperature cycles coincident with the design transients of the plant, which are listed in LRA Table 4.3-1. The staff noted that the total number of transients that occurred until May 26, 2012, for the design transient set was significantly less than the 7,000-cycle limit. The staff also noted that the total number of transients expected to occur through 60 years of operation for the design transient set is still significantly less than the 7,000-cycle limit. In both instances, the staff finds that there is significant margin between the total number of transients and the 7,000-cycle limit; therefore, the staff finds that there is margin to account for unanticipated cycles for the design limits while maintaining the 7,000-cycle limit for these non-Class 1 piping and in-line components. The applicant stated that the control rod drive system experiences temperature changes during a plant trip. The staff noted that the design transients listed in LRA Table 4.3-1 that would be associated with plant trips is significantly less than the 7,000-cycle limit, with margin to account for unanticipated plant trips through the period of extended operation.

For other systems with transients that occur independent of plant heatups and cooldowns, the applicant stated that the emergency diesel generators and fire pump diesel engine are tested periodically (approximately monthly), which will not result in the total number of cycles exceeding 7,000. The staff noted that the estimated usage of the emergency diesel generators and fire pump diesel engine, which are not normally in service, through 60 years of operation is based on periodic surveillance testing and in response to infrequent abnormal operating conditions of the system. The staff noted that since these events occur infrequently, it is conservative to assume that the emergency diesel generators and fire pump diesel engine run no more than five times per year in response to these abnormal operating conditions of the system. The staff noted that the number of cycles through the period of extended operation for the emergency diesel generators and fire pump diesel engine is expected to be no more than 15 percent of the 7,000 allowable cycles; therefore, the staff finds that there is a significant margin to account for unanticipated cycles for these components through the period of extended operation.

For the water sampling system, the applicant stated that it primarily samples using a continuous flow stream that is not isolated between samples. The staff noted that since samples are taken from a continuous flow stream that is not isolated between samples, it does not cause a thermal cycle for each sample taken. The applicant stated that special samples may be drawn infrequently through isolated lines. The staff noted that these samples would result in a thermal cycle because they are taken through isolated lines rather than a continuous flow stream. Since samples are not normally taken in such a way that would cause a thermal cycle and special samples, which cause a thermal cycle, are infrequently taken, the staff finds it reasonable that the 7,000-cycle limit will not be exceeded during the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with the requirements of 10 CFR 54.21(c)(1)(i), that the TLAAs for fatigue of non-Class 1 piping and in-line components, 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 expected total number of full thermal range transients over the period of extended operation for non-Class 1 piping and in-line components does not exceed the 7,000-cycle limit, with significant margin to account for unanticipated cycling.

4.3.2.1.3 UFSAR Supplement

LRA Section A.2.2.2, as amended by letter dated February 29, 2012, provides the UFSAR supplement summarizing the TLAA for fatigue of non-Class 1 piping and in-line components. The staff reviewed LRA Section A.2.2.2 consistent with 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 non-Class 1 piping and in-line components, as required by 10 CFR 54.21(d).

4.3.2.1.4 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 non-Class 1 piping and in-line components 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).

4.3.2.2 Non-Class 1 Fatigue – Non-Piping Components

4.3.2.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2.2.describes the applicant's non-Class 1 non-piping component fatigue analyses. The LRA states that non-Class 1 components other than piping system components require fatigue analyses if they were built to a section of the code such as ASME Section III, NC-3200 or ASME Code Section VIII, Division 2. The applicant's review of the non-Class 1 components other than piping identified non-Class 1 fatigue analysis applicable to expansion joints.

The applicant dispositioned the metal fatigue TLAA for non-Class 1 non-piping components in accordance with 10 CFR 54.21(c)(1)(i), that the non-Class 1 non-piping component stress calculations remain valid for the period of extended operation.

4.3.2.2.2 Staff Evaluation

The staff reviewed the applicant's metal fatigue TLAA for non-Class 1 non-piping components and the corresponding disposition of 10 CFR 54.21(c)(1)(i) consistent with 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 4.3.2.2 states a review of the non-Class 1 non-piping components identified fatigue analysis applicable to expansion joints. In addition, an evaluation of these analyses determined the number of cycles were adequate for 60 years of operation. However, the staff noted that the LRA did not identify the cycles or transients that these expansion joints were analyzed for and information regarding the number of occurrences for these cycles through the period of extended operation to support the disposition in accordance with 10 CFR 54.21(c)(1)(i). By letter dated May 24, 2012, the staff issued RAI 4.3-5 requesting the applicant to identify the cycles or transients that were considered as an input to the fatigue analyses of the expansion joints. In addition, the applicant was requested to justify the evaluation, referenced in LRA Section 4.3.2.2, which was performed for these expansion joint analyses that determined the number of cycles were adequate for 60 years of operation.

In its response dated June 21, 2012, the applicant stated that the cycles identified in the expansion joint design specifications varied by the location and use of the expansion joint as well as the level of complexity of the design specification. Furthermore, for simplicity, some locations specified a large number of thermal or dynamic cycles at the maximum joint expansion expected under any conditions. The applicant clarified that these components are not within the RCPB so there is no TS or UFSAR requirement to track the associated transients. Therefore, accumulated numbers of cycles are available only for cycles that also must be tracked for Class 1 components, such as SRV lifts and earthquakes (information regarding these transients are in LRA Table 4.3-1).

The applicant also stated that the allowable numbers of cycles for the other transients are well beyond reasonably postulated numbers of the transients, making it unnecessary to monitor these transients. The applicant explained that the design specifications identified a conservative number of cycles at a given amount of expansion so that simplified analyses could be performed and the typical analysis shows the expansion joint is qualified for many more cycles than was specified with these simplified bounding assumptions. The applicant reiterated that it completed a review of these analyses to verify the expansion joints are adequate for 60 years.

However, the applicant did not provide the number of cycles that the design specifications identified for non-Class 1 expansion joints and the expected number of cycles through the period of extended operation; therefore, the staff was not able to verify the adequacy of the disposition of the TLAA in accordance with 10 CFR 54.21(c)(1)(i). By letter dated August 7, 2012, the staff issued follow-up RAI 4.3-5a requesting information for the number of cycles that the design specifications identified for non-Class 1 expansion joints and the expected number of cycles through the period of extended operation. In addition, the applicant was asked to describe the details of the review that was completed for these expansion joint fatigue analyses to verify that the components are adequate for 60 years of operation and to justify that this review and evaluation demonstrate the disposition in accordance with 10 CFR 54.21(c)(1)(i).

In its response dated September 4, 2012, the applicant provided a table listing its non-Class 1 expansion joints. For several of these expansion joints, the applicant provided the usage factor associated with the design cycles and the applicant explained that, based on the usage factor, these expansion joints are acceptable for many more cycles than specified. Furthermore, for other expansion joints without usage factors, the applicant provided the number of cycles for which the specific expansion joint was designed or qualified. As part of the evaluation, the applicant stated that the expansion joints without usage factors were qualified to a number of cycles that is greater than the design cycles; therefore, the expansion joints are acceptable for many more cycles than specified.

The staff noted that although the expansion joints may have a low usage factor when compared to the design limit of 1.0, the low usage factor by itself does not support the disposition that the analysis remains valid for the period of extended operation. Similarly, the staff noted a component being “qualified” for many more cycles compared to the design cycles does not support the disposition that the analysis, which is based on the number of design cycles, remains valid for the period of extended operation (i.e., 10 CFR 54.21(c)(1)(i)). Furthermore, the applicant also did not provide AMR results in the LRA for these expansion joints subject to metal fatigue.

By letter dated October 3, 2012, the staff issued Follow-up RAI 4.3-5b requesting the applicant provide adequate justification for the disposition of 10 CFR 54.21(c)(1)(i), by demonstrating that the design number of cycles used in the original analysis will not be exceeded during the period of extended operation or, revise the TLAA disposition with adequate justification. The applicant was also requested to provide the AMR results for all non-Class 1 expansion joints in accordance with 10 CFR 54.21(a)(1).

In its response dated October 22, 2012, the applicant revised the TLAA disposition of certain expansion joints that have CUF values for their fatigue design. The applicant has multiplied its 40-year design CUF values by 1.5 to obtain the 60-year projected CUF values and concluded that the 60-year CUF values would not exceed the design limit of 1.0 and, therefore, dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(ii). The staff’s review of the applicant’s dispositions for the TLAAs associated with these non-Class 1 expansion joints with CUF values are discussed later. However, the applicant did not revise the UFSAR supplement in LRA Section A.2.2.2 indicating that, for these expansion joints, the metal fatigue TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

The applicant did not demonstrate that the design number of cycles used in the original analysis of the expansion joints in the standby liquid control (at tank outlet and pump inlets), high pressure core spray (diesel exhaust), and compressed air (air accumulators) will not be exceeded during the period of extended operation.

By letter dated November 30, 2012, the staff issued RAI 4.3-5c requesting the applicant provide, for expansion joints discussed above, adequate justification for the disposition of 10 CFR 54.21(c)(1)(i), by demonstrating that the number of cycles used in the design analysis will not be exceeded during the period of extended operation. The applicant was also requested to revise UFSAR supplement in LRA Section A.2.2.2 indicating that certain metal fatigue TLAAs for expansion joints have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

In its response dated December 18, 2012, the applicant revised LRA Section A.2.2.2. In addition, the applicant clarified that the analysis for the standby liquid control system (at tank outlet and pump inlets) expansion joints did not use the design value of cycles (1,000). Instead, the analysis used the magnitude of movement (0.125 inch) as an input and determined that 400,000 cycles are allowed for this component. Therefore, even if the original number of cycles in the design specification for this component (1,000) is multiplied by the ratio of 60 years to 40 years (1.5), the result does not exceed the acceptable qualified value of 400,000 cycles determined in the analysis for the component. The staff noted that the analysis qualified the component for 400,000 cycles, as opposed to the 1,000 cycles, as previously characterized by the applicant. Similarly, the applicant clarified that the analysis for the high pressure core spray diesel exhaust expansion joints determined that 4000 cycles are allowed for this component. Therefore, even if the original number of cycles in the design specification for this component (1,200) is multiplied by the ratio of 1.5, the result does not exceed the acceptable qualified value of 4,000 cycles. The applicant also clarified that the analysis for the expansion joints of the compressed air accumulators determined that 10,000 cycles are allowed for this component. Therefore, even if the original number of cycles expected in the design specification for this component (700) is multiplied by the ratio of 1.5, the result does not exceed the acceptable qualified value of 10,000 cycles.

The staff finds the use of the 1.5 factor for projecting future transient occurrence for these 3 sets of expansion joints described above to be reasonable because the resulting estimated 60-year occurrence provides a gauge of the margin available prior to the qualified limit being reached. In any event, the number of expected cycles through the period of extended operation is expected to be no more than 45 percent of the qualified cycles; therefore, there is a sufficient amount of margin to account for unanticipated cycles for these expansion joints.

Based on its review, the staff finds the applicant’s response to RAI 4.3-5c acceptable because the applicant justified that the cycles experienced by these expansion joints will not exceed the qualified number of cycles established in the design analysis during the period of extended operation. Furthermore, the staff also finds the applicant’s response acceptable because LRA Section A.2.2.2 was revised to accurately summarize and provide the details of how the metal fatigue TLAA for non-Class 1 expansion joints with usage factors have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(d). The staff’s concerns described in RAIs 4.3-5, 4.3-5a, 4.3-5b, and 4.3-5c are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for expansion joints without usage factors 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 numbers of cycle over the period of extended operation for these expansion joints do not exceed the original design limit, with margin to account for unanticipated cycling of these components.

The staff reviewed LRA Section 4.3.2.2, as amended by letter dated December 18, 2012, and the TLAA for non-Class 1 expansion joints with CUF values to verify that in accordance with 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation.

In its response dated October 22, 2012, the applicant multiplied its 40-year design CUF values by 1.5 to obtain the 60-year projected values and concluded that the 60-year CUF values would not exceed the design limit of 1.0. The staff noted that the highest 60-year CUF among this set of expansion joints is 0.15, which is significantly below the design limit of 1.0. The staff finds that 1.5 projection basis provides a reasonable scale to project the 40-year design CUF to 60 years, and the resulting estimated 60-year CUF provides a gauge of the margin available before the design limit of 1.0 is reached.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the fatigue analyses for certain expansion joints with CUF values have been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria of SRP-LR Section 4.3.2.1.1.2 because the applicant has demonstrated that the recalculated CUF values through 60 years of operation are less than the design limit of 1.0 with margin to account for additional fatigue usage.

4.3.2.2.3 UFSAR Supplement

LRA Section A.2.2.2, as amended by letter dated December 18, 2012, provides the UFSAR supplement summarizing the TLAA for non-Class 1 non-piping components. The staff reviewed LRA Section A.2.2.2 consistent with 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 metal fatigue TLAA.

Based on its review of the UFSAR supplement, as amended by letter dated December 18, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address non-Class 1 non-piping components, as required by 10 CFR 54.21(d).

4.3.2.2.4 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 fatigue analyses for non-Class 1 expansion joints without usage factors remain valid for the period of extended operation. The staff also concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for non-Class 1 expansion joints with CUF values 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).

4.3.3 Effects of Reactor Water Environment on Fatigue Life

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3.describes the applicant's evaluation to address the effects of reactor water environment on fatigue life. The LRA describes an evaluation for the six locations using NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," issued February 1995, which addresses the application of environmental correction factors to fatigue analyses. Specifically, NUREG/CR-6260, Section 5.6, identified certain component locations to be the most sensitive to environmental effects for newer vintage GE plants, which are directly relevant to the applicant. The LRA also states that additional locations were evaluated beyond the six locations identified in NUREG/CR-6260; specifically, the highest usage factor was evaluated in the piping in the FW, reactor recirculation, RHR, LPCS, and HPCS systems.

The LRA states that the applicant will review design basis ASME Code Class 1 component fatigue evaluations to ensure the GGNS locations evaluated for the effects of the reactor coolant environment on fatigue include the most limiting components within the RCPB. The LRA provides a list of formulae that will be used to address the environmental effects on fatigue for these critical components for carbon and low-alloy steel, austenitic stainless steel, and nickel alloy materials. Furthermore, if an acceptable CUF cannot be calculated, the applicant stated it will repair or replace the affected locations before exceeding an environmentally adjusted CUF of 1.0.

The applicant dispositioned the analyses to address the effects of reactor water environment on fatigue life in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of EAF on the intended functions of the analyzed components will be adequately 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), "Fatigue Evaluation of Metal Components for 60-Year Plant Life," issued December 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 CLB of GGNS. 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 analyses to address the effects of reactor water environment on fatigue life and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with 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 F_{en} values which are calculated with the recommended sets of formulae in NUREG/CR-5704,"Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steel," issued April 1999; NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy

Steels," issued February 1998; and NUREG/CR-6909, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials – Final Report," issued February 2007.

The staff noted that LRA Section A.2.2.3 indicates that, before the period of extended operation, the applicant will update the fatigue usage calculation using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor coolant environment. In addition, LRA Table 4.3-7 indicates that the applicant has not calculated the environmentally-adjusted CUF for nickel-based alloy components and that there are many locations with EAF CUFs greater than 1.0. However, the staff noted that neither the LRA nor its UFSAR supplement provide a sufficient description of how CUF values will be refined and F_{en} factors will be calculated. Without a description of how the Fatigue Monitoring Program will be permitted to refine the CUF and calculate the F_{en} factors, the staff is unsure as to how the program will manage the effects of reactor coolant environment on metal fatigue during the period of extended operation. By letter dated May 24, 2012, the staff issued RAI 4.3-8 requesting the applicant to provide and justify the methods that will be used to refine the CUF and F_{en} values and to revise LRA Section A.2.2.3 to provide this description, as necessary.

In its response dated June 21, 2012, the applicant provided an explanation of the conservatism in the original design basis fatigue calculations that are meant to simplify the analyses, such as combining all transients together and considering them all to be as severe as the worst transient for a particular location. The applicant stated that to account for EAF, design basis fatigue analyses may be revised to reduce the conservatism to meet the criterion on CUF of 1.0. Such techniques include the consideration of actual severity of historical transients to reduce assumed cyclic loads from being as severe as the assumed design basis transients. In addition, the applicant stated that conservatism also may be reduced for specific locations by considering 60-year projected cycles if they are less than the design basis numbers of cycles. Furthermore, a detailed NB-3200 calculation may be performed if the reduction in conservatism in the design basis fatigue analyses is not possible.

The staff finds the techniques that the applicant described to reduce conservatism in the fatigue analyses are appropriate because they consider the actual circumstances of transients, such as transient severity, number of cycles, and treating transients separately, rather than using worse-case scenarios or design basis assumptions. The staff noted that these techniques are commonly used because they are effective and yield successful results; but the staff noted that they are not the only possible techniques to refine CUF values. In addition, the staff finds it appropriate that calculations may be performed in accordance with ASME Code, Section III, Subsection NB because 10 CFR 50.55a approves its use for the design of RCPB components.

The applicant stated that the specific approach to refining the analysis will vary from calculation to calculation and that speculating on the specific approaches in the UFSAR supplement would be inappropriate. Since the use of any combination of techniques to refine a fatigue analysis will vary depending on the circumstances of each calculation, the staff agrees that it is not appropriate to provide the specifics in the UFSAR supplement. The applicant stated that LRA Section A.2.2.3 indicates that CUFs will be determined using an NRC-approved version of the ASME Code or NRC-approved alternative. In addition, LRA Section A.2.2.3 was revised in the applicant's response to state "[e]nvironmental effects on fatigue for these critical components will be evaluated using one of the following sets of formulae in accordance with the guidance in NUREG-1801, Revision 2, Section X.M1."

The staff finds it acceptable that the UFSAR supplement indicates the use of an NRC-approved version of the ASME Code or NRC-approved alternative to calculate CUFs because

10 CFR 50.55a identified the versions of the ASME Code that have been approved for use; specifically, 10 CFR 50.55a(b) provides approved versions of ASME Code, Section III to perform CUF-related calculations. The staff also finds it acceptable that the UFSAR supplement indicates the use of the formulae in the staff's guidance document, NUREG-1801, Revision 2, Section X.M1, to determine the F_{en} factor to address EAF.

The staff finds the applicant's response to RAI 4.3-8 acceptable because (1) the determination of CUF will be performed in accordance with a version of the ASME Code, as approved for use in 10 CFR 50.55a, or a staff-approved alternative; (2) the determination of the F_{en} factor will be performed consistent with formulae in the GALL Report; and (3) this information is captured in the applicant's UFSAR supplement to provide a summary description of activities for managing EAF. The staff's concern described in RAI 4.3-8 is resolved.

LRA Section 4.3.3 provides a description of operating times of the plant with normal water chemistry (NWC) and hydrogen water chemistry (HWC). It also states that EAF analyses included an evaluation of the water chemistry history using a time-weighting methodology to determine the "cumulative environment" for the components when determining the dissolved oxygen.

The staff noted that the use of a time-weighted percentage for NWC and HWC to evaluate EAF is based on the assumption that transients occurred linearly from the time of initial plant operation. However, based on information the staff noted during its audit and from LRA Table 4.3-1, this may not always be the case. It is possible that the use of a time-weight percentage for HWC/NWC in the formulation of F_{en} values may underestimate the environmentally-adjusted CUFs. The applicant did not explain why the use of a time-weighted percentage for NWC/HWC is acceptable when evaluating EAF, and LRA Section A.2.2.3 did not provide an adequate description on the treatment of NWC and HWC in the current and future EAF CUF analyses. By letter dated May 24, 2012, the staff issued RAI 4.3-9, requesting the applicant to justify that the use of a time-weighted percentage for HWC/NWC operation to calculate F_{en} values is appropriate or conservative, instead of incorporating available information for transient occurrences during NWC/HWC operation for the calculations that support LRA Section 4.3.3 and the EAF CUF calculations that will be performed in the future. The applicant was also requested to revise LRA Section A.2.2.3 to provide a description of the methodology to address NWC/HWC operation for the future analyses to determine valid EAF CUF values, as necessary.

In is response dated June 21, 2012, the applicant stated that the enhancement for the Fatigue Monitoring Program will be performed using industry-accepted techniques for consideration of the effects of the reactor water, including techniques for incorporating the impact of dissolved oxygen concentration into the calculation of the F_{en} factor.

The applicant clarified that the discussion related to dissolved oxygen concentrations in LRA 4.3.3 and the information in LRA Table 4.3-6 will not be used to review the effects of EAF or to accept any location as a bounding location. The applicant also revised LRA Section A.2.2.3 to include the following, "[i]ndustry-accepted techniques will be used for consideration of the effects on fatigue of the reactor water environment (environmentally assisted fatigue – EAF), including techniques for incorporating the impact of dissolved oxygen concentration into the calculation of fatigue environmental correction factors."

The staff noted that it is possible these industry-accepted techniques may not or will not be approved for use by the staff. Furthermore, the staff noted that the concern identified in

RAI 4.3-9 specifically addressed the use of a time-weighted percentage for HWC/NWC in the formulation of F_{en} values and that this use may underestimate the environmentally-adjusted CUFs. The applicant has not explained how the use of unspecified industry-accepted techniques will resolve this potential non-conservatism. By letter dated August 7, 2012, the staff issued follow-up RAI 4.3-9a requesting the applicant to revise LRA Section A.2.2.3 to indicate that future calculation of F_{en} values will incorporate available transient cycle occurrence data during operating times in NWC and HWC instead of using a time-weighted percentage for NWC and HWC operation.

In its response dated September 4, 2012, the applicant revised its UFSAR supplement in LRA Section A.2.2.3 indicating that future calculations of F_{en} values will incorporate available transient cycle occurrence data during operating times in NWC and HWC. The staff noted that the applicant's methodology will eliminate the under-estimation of the environmentally-adjusted CUFs due to a time-weight percentage for HWC/NWC in the F_{en} values formulation. The staff noted that by updating the UFSAR supplement, the applicant provided an adequate description on the treatment of NWC and HWC in future EAF CUF analyses.

The staff finds the applicant's response to RAI 4.3-9a acceptable because (a) future calculations of EAF CUF will incorporate available information for transient occurrences during NWC/HWC operation, and (b) this information is captured in the applicant UFSAR supplement to provide a summary description of activities for managing environmentally-assisted fatigue. The staff's concerns described in RAIs 4.3-9 and 4.3-9a are resolved.

The applicant assessed the effects of reactor water environment on fatigue life in LRA Section 4.3.3 by applying the F_{en} factors to the CUF values and the resulting CUF_{en} values are greater than 1.0 in many cases. The staff noted that the UFSAR supplement in LRA Section A.2.2.3 indicates that, prior to the period of extended operation, the applicant will update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. The applicant also dispositioned the evaluations to address the effects of reactor water environment on fatigue life in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of environmentally-assisted fatigue on the intended functions of the analyzed components will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff also noted that, consistent with Commission Order No. CLI-10-17, the regulations contain no requirement that an applicant complete an EAF analysis *prior* to the issuance of a renewed license. Therefore, the staff finds it reasonable that the applicant will update the fatigue usage calculation using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment prior to the period of extended operation because this information is captured in the applicant's UFSAR supplement to provide a summary description of activities for managing EAF.

The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.1.18. The staff determined that the AMP includes three monitoring methods (cycle counting, cycle-based fatigue monitoring and stress-based fatigue monitoring) that are capable of managing metal fatigue and EAF during the period of extended operation. The staff also determined that the use of these three monitoring methods progressively provides a more refined monitoring approach to manage metal fatigue and EAF to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of EAF on the intended functions 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 4.3.2.1.3 because the applicant is crediting its Fatigue Monitoring Program, which the staff determined in SER Section 3.0.3.1.18 is consistent with GALL Report AMP X.M1, to manage EAF to ensure that the allowable design limits on fatigue usage are not exceeded 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.2.2.3, as amended by letters dated June 21, 2012, and September 4, 2012, provides the UFSAR supplement summarizing the evaluations for the effects of reactor water environment on fatigue life. The staff reviewed LRA Section A.2.2.3 consistent with 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.

Based on its review of the UFSAR supplement, as amended by letters dated June 21 and September 4, 2012, 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 evaluate the effects of reactor water environment on 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 has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor water environment on fatigue life 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 appropriate summary description of the EAF evaluations, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification of Electric Equipment

The 10 CFR 50.49 Environmental Qualification (EQ) program is a TLAA for the purposes of license renewal. The TLAA of the EQ electrical components includes all long-lived, passive, and active electrical and instrumentation and controls (I&C) components that are important to safety and located in a harsh environment. The harsh environments of the plant are those areas subject to environmental effects by LOCAs or HELBs. EQ equipment comprises safety-related and Q-list equipment, nonsafety-related equipment, the failure of which could prevent satisfactory accomplishment of any safety-related function, and necessary post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of EQ TLAAs in the LRA. The applicant shall demonstrate that for each type of EQ equipment, one of the following is true: (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, or (3) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

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.

The applicant dispositioned the TLAA for the electric equipment in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions will be adequately managed by the Environmental Qualification (EQ) of Electric Components Program for the period of extended operation.

4.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the electric equipment consistent with SRP-LR Section 4.4.2.1, which states that, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), an applicant must demonstrate that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The EQ 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 DBAs.

The staff reviewed LRA Sections 4.4 and B.1.17, plant basis documents, additional information provided to the staff, and interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirements 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 for the period of extended operation. Per the GALL Report, plant EQ Programs that implement the requirements of 10 CFR 50.49 are considered acceptable AMPs in accordance with 10 CFR 54.21(c)(1)(iii). GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components," provides a way 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 ensure 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 components qualification focused on how the EQ Program manages the aging effects to meet the requirements pursuant to 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Sections 4.4 and B.1.17 and the program basis documents. LRA Section B.1.17 discusses the component reanalysis attributes, including analytical models, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. The staff's review of the applicant's EQ of Electrical Components is documented in SER Section 3.0.3.1.16. On the basis of its audit, the staff finds that the EQ 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 (EQ) of Electric Components Program will be implemented per the requirements of 10 CFR 54.21(c)(1)(iii).

The staff finds the applicant has demonstrated pursuant to10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of the electric equipment 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 applicant's EQ 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 of Electric Components Program provides assurance that the aging effects will be managed and that components within the scope of the EQ of Electric Components Program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

LRA Section A.1.17 provides the UFSAR supplement summarizing the Environmental Qualification (EQ) of Electric Equipment TLAA. The staff reviewed LRA Section A.1.17 consistent with SRP-LR Section 4.4.1.3, which states that the detailed information on the evaluation of TLAAs is contained in the renewal application. A summary description of the evaluation of TLAAs for the period of extended operation is contained in the applicant's UFSAR supplement.

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 (EQ) of Electric Equipment 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, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of the electric equipment will be adequately managed by the Environmental Qualification (EQ) of Electric Components Program 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 Concrete Containment Tendon Prestress Analyses

4.5.1 Summary of Technical Information in the Application

LRA Section 3.5.2.2.1.4, "Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature," states that the GGNS containment structure is constructed of reinforced concrete with no prestressed tendons associated with its design. Therefore, loss of prestress due to relaxation, shrinkage, creep, and elevated temperature do not apply. Accordingly, the applicant dispositioned the Concrete Containment Tendon Prestress TLAA assigned by NUREG-1800 Section 4.5, by stating in LRA Section 4.5, "Concrete Containment Tendon Prestress," that the section is not applicable.

4.5.2 Staff Evaluation

The staff reviewed relevant containment design information in the UFSAR to evaluate the validity of the applicant's basis. The staff reviewed the description provided in Table 1.3-4, “Comparison of Containment Design Characteristic,” of the UFSAR, which attests that the containment is a “[r]einforced concrete cylindrical structure (not prestressed) with hemispherical head; steel lined.” Based on this review, the staff has confirmed that the design of the containment structure is not reinforced with prestressed tendons; therefore, the staff finds that this TLAA is not required.

4.5.3 UFSAR Supplement

The staff concludes that no UFSAR supplement is required because the containment building has no prestressed tendons.

4.5.4 Conclusion

On the basis of its review, as discussed above, the staff concludes this TLAA is not required.

4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses

4.6.1 Containment Liner Plate, Metal Containments

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6.1 describes the applicant’s TLAA for the containment liner plate and metal containments fatigue analysis. The LRA states that the containment is a BWR Mark III. The applicant stated that, as described in UFSAR Section 3.8.1.3, the containment was designed in accordance with the loads defined in GE Topical Report NEDO 11314-08 (GESSAR Appendix 3B) and that additional loads defined in GE 22A4365 and later defined by GE 22A7000, Revision 2, were considered for the final design verification of the containment.

The LRA states that the quenchers were designed for a conservatively high value of 18,000 cycles and the usage factors were calculated to be much less than 1.0: usage factors for the quencher arm, arm-to-shell juncture, support arm, support arm weld, and stiffening ring were 0.018. The calculated fatigue usage factor at the support arm to shell connection was 0.23. The LRA states that the SRV actuations are tracked and will be maintained below the value used in the fatigue evaluation.

The LRA states that the suppression pool and cylinder wall liner plate fatigue analysis was performed using Subsections NE and NB of the ASME Code Section III, 1971 Edition with Summer 1973 Addenda. The calculated fatigue usage was less than 0.02 with a total number of 19,362 cycles, including heatups and cooldowns, seismic cycles, and SRV actuations.

The applicant dispositioned the TLAA for the containment liner plate and metal containment components in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue on the primary containment will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.1.2 Staff Evaluation

The staff reviewed the applicant’s TLAA for the containment liner plate and metal containment components and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with SRP-LR Section 4.6.3.1.1.3, which states that the applicant’s proposed AMP to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation is reviewed. If the program will replace the component before its CUF exceeds 1, the review verifies that the CUF for the replacement will remain less than or equal to 1 during the period of extended operation.

The staff reviewed UFSAR Appendix 6A, Section 3BA.7, which states that the GGNS quencher rests in bearing on the containment basemat. The quencher component includes the stiffening ring subcomponent shown on UFSAR Appendix 6A, Figure A-2. A large cylindrical support arm extends from the quencher to the drywell wall, which takes moments and lateral and vertical-up forces. Vertical-down forces are taken by the support arm and the basemat. The staff confirmed in UFSAR Appendix 6A, Section 3BA.7, that the quenchers were designed to 18,000 fatigue cycles and that for all quencher components, the fatigue usage factors calculated were significantly lower than 1.

The staff reviewed UFSAR Section 3.8.1.3 and confirmed that the initial design of the GGNS Mark III containment was in accordance with the loads defined in GE Topical Report NEDO 11314-08 (GESSAR Appendix 3B), and that additional loads initially defined in GE 22A4365, Interim Containment Loads Report, Revision 2, and later defined in GE 22A7000, Revision 2 (GESSAR II, Appendix 3B), were considered in the final design verification of the containment. The staff reviewed UFSAR Section 3.8.1.1.2 and noted that the concrete containment is lined completely with a welded steel liner plate to form a leak-tight barrier that minimizes radioactive leakage to the environment. The staff reviewed UFSAR Section 3.8.1.4.2 and noted that the liner plate was designed in accordance with Bechtel Corporation Topical Reports BC-TOP-1 and BC-TOP-5A. The UFSAR states that the GGNS [containment] liner plate is backed by concrete and does not classify as a pressure boundary, and is therefore not designed in accordance with ASME Code Section III, Division I. The staff did not find a fatigue analysis for the containment liner and agrees that it does not need to be analyzed for fatigue because it is integral with the concrete that backs it. Further, it is not credited as a pressure boundary. The suppression pool liner plate is fabricated out of stainless steel and was designed to be affected by periodic negative pressure loading due to the SRV discharge. The staff noted that, for this reason a fatigue evaluation of the suppression pool liner was performed using Subsections NE and NB of the ASME Code, Division I, Section III, 1971 Edition with Summer of 1973 Addenda. The LRA states that it calculated a CUF value of less than 0.02 with a total number of cycles of 19,362, including the transient cycles associated with heatups and cooldowns, seismic cycles, and SRV actuations. Furthermore, the heatups and cooldowns, seismic cycles, and SRV actuations are tracked against limits that are well below the total cycle value used in the liner fatigue evaluation.

SRP-LR Section 4.6.2.1.1.3 states that an acceptable method for meeting the requirements of 10 CFR 54.21(c)(1)(iii) is that an AMP provided by the applicant shall demonstrate that the effects of aging on the component's intended functions will be adequately managed during the period of extended operation. The staff noted that the applicant is monitoring transient cycles with the Fatigue Monitoring Program. The applicant's Fatigue Monitoring Program tracks SRV actuations for fatigue of the quenchers and will ensure that SRV actuations are maintained below the value used in the fatigue analysis. The Fatigue Monitoring Program also tracks heatups, cooldowns, seismic cycles, and SRV actuations for fatigue of the suppression pool and cylinder wall liner plate.

The staff finds the applicant has demonstrated in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment liner plate and metal containment components will be adequately managed for the period of extended operation. Additionally, the TLAA disposition meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the applicant's Fatigue Monitoring Program will monitor transient cycles and take action before any of the transients meets its analyzed number of occurrences.

4.6.1.3 UFSAR Supplement

LRA Section A.2.4 provides the UFSAR supplement summarizing the containment liner plate and metal containments TLAA. The staff reviewed LRA Section A.2.4 consistent with SRP-LR Section 4.6.3.2, 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 containment liner plate and metal containments fatigue TLAA.

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 is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address containment liner and metal containment components, 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, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment liner plate and metal containments 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 appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.2 Containment Penetrations

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.2 describes the applicant's TLAAs for the containment penetrations. The LRA states that ASME Class 1 piping that has guard pipes with flued heads for containment penetration welded to the piping has individual analyses for fatigue at each penetration. The LRA states that Class 1 fatigue analyses for the following flued head penetrations: Main Steam, Main FW, RHR, RCIC, Main Steam Drain, multiple RHR/LPCI penetrations, HPCS, LPCS, and RWCU. The calculated usage factors are shown in LRA Table 4.6-2.

The LRA cites UFSAR Figure 3.6A-33 in stating that the guard pipe assemblies use bellows. The applicant also cites UFSAR Figure 9.1-15 and Section 9.1.4.2.3.11 in stating that the fuel transfer tube also uses bellows. The applicant stated that calculations were identified for the bellows that analyzed a large number of cycles of flexure due to normal operation and earthquakes. Those calculations are considered TLAAs. In both the cases of the guard pipe bellows and the fuel transfer tube bellows, the applicant stated that the number of analyzed cycles is significantly higher than the total number of cycles projected for the period of extended operation.

The applicant dispositioned the TLAAs for the containment penetrations in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.2.2 *Staff Evaluation*

The staff reviewed the applicant's TLAA for the containment penetrations, and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with SRP-LR Section 4.6.3.1.1.3, which states that the applicant's proposed AMP to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation is reviewed. If the program will replace the component before its CUF exceeds 1, the review verifies that the CUF for the replacement will remain less than or equal to 1 during the period of extended operation.

The staff reviewed the UFSAR and found no additional systems with piping penetrations that included a flued head and individual fatigue analysis. The staff also noted from LRA Table 4.6-2, which identified the result of each analysis and grouped the analyses into what the applicant stated were "simplified bounding load cases," that each penetration analyzed to a CUF of less than one. The staff also reviewed LRA Table 4.3-1 and UFSAR Section 3.9.1.1 for documentation of analyzed transients and noted that the current and projected transient cycles for 60 years of operation are less than the design cycle limits.

For the bellows on the containment penetration guard pipes and fuel transfer tube, the staff noted that the applicant stated it analyzed a large number of cycles of flexure due to normal operation and earthquakes. The staff also noted the applicant's statement that the number of analyzed cycles is significantly higher than the total number of cycles projected for the period of extended operation and that the applicant will use the Fatigue Monitoring Program to manage the aging effects. However, the staff noted that the LRA does not provide additional information regarding the calculations performed for the fatigue analysis, such as the number of analyzed cycles or the included transients. Therefore, the staff identified that it needed further information to confirm that the evaluation for the fatigue analysis remains valid for the period of extended operation. By letter dated June 27, 2102, the staff issued RAI 4.6.2-1 requesting that the applicant identify the number of cycles that the bellows for the guard pipes and fuel transfer tubes were designed for and explain how that number was developed. The staff also requested that the applicant identify which transients were included in the original evaluation and which ones will be monitored under the Fatigue Monitoring Program.

By letter dated July 25, 2012, the applicant responded to RAI 4.6-2, stating that the design specification for the penetration bellows indicates specific values of movement for normal conditions and for accident conditions. The applicant stated that the main steam secondary containment penetration bellows at the turbine building to auxiliary building interface has the lowest number of allowable cycles for penetration bellows, with an allowable value of 10,000 cycles of movement. The applicant also stated that the number of times the main steam lines are heated up (as part of plant startup) plus the total number of earthquake cycles will remain well below the allowable 10,000 cycles through the period of extended operation. The applicant further stated that the other penetration bellows are qualified for many more movement cycles (up to 100,000 or 1,000,000) and that these allowable cycles are significantly higher than the total number of piping thermal movements, pressurization cycles, and seismic movement cycles expected for the period of extended operation.

The staff finds the applicant's response acceptable because the applicant has identified the most limiting analysis for this component type and all other penetration bellows are qualified for many more cycles. In addition, SRP-LR Section 4.6.2.1.1.3 states that an acceptable method for meeting the requirements of 10 CFR 54.21(c)(1)(iii) is that an AMP provided by the applicant shall demonstrate that the effects of aging on the component's intended functions will be adequately managed for the period of extended operation. The staff noted that the applicant is monitoring transient cycles affecting the penetration and fuel transfer tube bellows, including piping thermal movements, pressurization cycles, and seismic movement cycles, using the Fatigue Monitoring Program. The staff's concerns described in RAI 4.6-2 are resolved.

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 containment penetrations will be adequately managed for the period of extended operation. Additionally, the applicant's demonstration meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the applicant's Fatigue Monitoring Program will monitor transient cycles and take action before any of the transients meets its analyzed numbers.

4.6.2.3 UFSAR Supplement

LRA Section A.2.4 provides the UFSAR supplement summarizing the containment penetrations TLAA. The staff reviewed LRA Section A.2.4 consistent with SRP-LR Section 4.6.3.2, 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 containment penetrations fatigue TLAA.

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 is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the containment penetrations TLAA, 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, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment penetrations 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 appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific TLAAs

LRA Section 4.7, as amended by letter dated October 2, 2012, summarizes the evaluation of the following plant-specific TLAAs:

- Erosion of the MSL Flow Restrictors
- Determination of Intermediate High-Energy Line Break Locations
- Fluence Effects for the Reactor Vessel Internals
- Fatigue Analysis of Cranes

4.7.1 Erosion of the MSL Flow Restrictors

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 describes the applicant's TLAA for the erosion of the main steam line flow restrictors. The LRA refers to UFSAR Section 5.4.4.4, which indicates that very slow erosion of the flow restrictors occurs with time, and 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 states that the evaluation of erosion-corrosion rate for the main steam flow elements considered the specific material present in the GGNS flow restrictors and determined that the expected rate, when operating at the velocities that would be present following EPU, would be much less than the conservative value in the UFSAR. The LRA also states that, using the expected rate, the total erosion after 60 years would remain less than the conservative total erosion value identified in the UFSAR for 40 years.

The applicant dispositioned the TLAA for the erosion of the main steam line flow restrictor 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.

4.7.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the erosion of the main steam line flow restrictors and the corresponding disposition that the analysis has been projected to the end of the period of extended operation consistent with SRP-LR Section 4.7.3.1.2, which states that the results of the revised analyses are confirmed to ensure that they are valid for the period of extended operation.

The staff noted that the LRA did not contain information regarding the revised analyses to demonstrate that the choked flow will remain less than the 170 percent of normal flow or less than 6.91×10^6 pounds per hour at 1,025 psig upstream pressure in the event of a main steam line break, as stated in UFSAR Section 5.4.4. In addition, it was unclear to the staff to what value the LRA was referring in the statement "total erosion value identified in the UFSAR for 40 years," since a total erosion value was not given. By letter dated June 5, 2012, the staff issued RAI 4.7.1-1 requesting the applicant to provide the results of the projected analyses demonstrating that the intended functions of these components are maintained in accordance with the CLB, and to include the bases for concluding that the expected erosion rate would be much less than the value in the UFSAR.

In its response dated July 3, 2012, the applicant stated that the erosion rate of 0.004 inch per year stated in UFSAR Section 5.4.4.4 was highly conservative, and that information from a later evaluation shows that the expected flow restrictor erosion would be less than the 0.160 inch derived from the 0.004 inch per year for 40 years of operation. In addition, the applicant provided several attributes to explain the reduction in the erosion-corrosion rate from the 0.004 inch per year given in the UFSAR, including that materials with minimal chromium content are resistant to erosion-corrosion damage. However, the applicant did not provide any specific details regarding the revised analysis. In its review of the response, the staff noted that although the flow restrictors are constructed from stainless steel, the chromium content in stainless steel does not prevent loss of material due to erosion in all situations. The applicant's response did not provide sufficient information for the staff to complete its review of this issue. In order to resolve this concern, by letter dated September 7, 2012, the staff issued RAI 4.7.1-1a requesting the applicant to provide the evaluation discussed in its earlier response.

In its response dated October 2, 2012, the applicant provided NEDC-33668P, Revision 1, dated August 2011, "Grand Gulf Station Plant Life Extension Support Main Steam Line Flow Restrictors Material Review and Effect on Offsite Dose from Steam Release Due to Erosion-Corrosion." The staff reviewed Section 3, "Evaluation," regarding the erosion-corrosion rate and the impact to offsite dose due to increase in steam release. Based on review of Section 3 of this report, the staff verified that the expected erosion-corrosion rate of the main steam line flow restrictors is less than the rate assumed in UFSAR Section 5.4.4.4 and that the consequent increase in offsite dose is less than the 5 percent increase stated in UFSAR Section 5.4.4.4. The staff's concerns described in RAIs 4.7.1-1 and 4.7.1-1a are resolved.

The staff finds that the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis for the main steam line flow restrictor erosion has been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.3.1.2 because the revised report reevaluated the overly conservative assumptions in the original analysis to show that the TLAA acceptance criteria continue to be satisfied for the period of extended operation.

During its review of LRA Table 3.1.2-3, "Reactor Coolant Pressure Boundary," the staff noted that it includes cast austenitic stainless steel flow elements, which appear to be the main steam line flow restrictors. The table indicates that these components are being managed by the Water Chemistry – BWR Program, for cracking through item 3.4.1-11, and for loss of material through item 3.1.1-79. However, the staff noted that item 3.1.1-79 does not apply to loss of material due to erosion, and that Table 3.1.2-3 did not include a separate AMR item for the TLAA associated with erosion of the flow restrictors. In order to address this concern, by letter dated September 7, 2012, the staff issued RAI 4.7.1-2 requesting that the applicant provide an AMR item for the main steam line flow restrictors in LRA Table 3.1.2-3 that credits the TLAA for managing loss of material due to erosion. In its response dated October 2, 2012, the applicant revised LRA Table 3.1.2-3 by adding an AMR item for loss of material due to erosion of the flow element to indicate that it is being managed through a TLAA. The staff finds this response acceptable because the LRA now provides the aging management method used by GGNS to demonstrate that the effects of aging will be adequately managed for the main steam line flow restrictors. The staff's concern described in RAI 4.7.1-2 is resolved.

4.7.1.3 UFSAR Supplement

LRA Section A.2.5.1 provides the UFSAR supplement summarizing the erosion of the main steam line flow restrictors. The staff reviewed the LRA Section A.2.5.1 consistent with SRP-LR Section 4.7.3.2, which states that the information to be included in the UFSAR supplement includes 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).

4.7.1.4 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)(ii), that the analysis for the main steam flow restrictor erosion has 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).

4.7.2 Determination of Intermediate High-Energy Line Break Locations

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 describes the TLAA associated with the determination of intermediate HELB locations. The LRA states that the determination of HELB locations in UFSAR Section 3.6A.2 relied on an evaluation of piping systems that had been analyzed in accordance with CUF analyses. The applicant stated that, as long as the other stress criteria in the UFSAR section were met, pipe break would not need to be postulated for high-energy pipe location as long as the CUF value for the components was confirmed to be less than a value of 0.1. The applicant stated that, since these CUF calculations are based on design transients defined by the initial 40-year life of the plant, the CUF calculations are TLAAs for the LRA.

The LRA states that the Fatigue Monitoring Program will identify if the number of cycles for the high-energy piping systems are approaching their analyzed number of cycles. If the cycle limit on any transient will be exceeded, the design calculations for that system will be reviewed to determine if additional locations in that system need to be evaluated as potential HELB locations or if reanalysis would be required. As part of the periodic updates that consider actual plant transients, the program will ensure that the CUF values for piping locations where breaks were not postulated will not exceed a CUF value criterion of 0.1. Furthermore, if other locations are determined to require consideration as postulated pipe break locations, appropriate corrective actions will be taken to address the new break locations.

The applicant stated that the CUF evaluations for HELB locations are acceptable in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii), that the Fatigue Monitoring Program will be used to adequately manage the associated effects of aging on these locations for the period of extended operation.

4.7.2.2 Staff Evaluation

The staff reviewed the applicant's TLAA for HELB analyses and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with SRP-LR Section 4.3.2.1.1.3, which provide the NRC's recommended "acceptance criteria" for accepting CUF-based TLAAs in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii). SRP-LR Section 4.3.3.1.1.3 states that the applicant may reference GALL Report AMP X.M1 to accept the TLAA in accordance with 10 CFR 54.21(c)(1)(iii), and the reviewer should verify that the applicant's program contains the same program elements that were evaluated and relied upon in approving the corresponding generic program in the GALL Report. The staff evaluated the applicant's disposition against relevant information in applicable subsections and tables of UFSAR Chapter 3 and the criteria in 10 CFR Part 50, Appendix A, GDC 4, "Dynamic Effects." GDC 4 requires that the design of nuclear power plants be sufficient to protect safety-related components, structures, or equipment against dynamic effects, including missiles, pipe whips, and discharge of fluids that may result from equipment failures or events and conditions outside of the nuclear power plant.

The staff determined that UFSAR Section 3.6 provides the basis for meeting GDC 4. This UFSAR section provides the design basis for identifying those plant piping components that need to be identified as high-energy pipe break locations for the applicant's design basis, such that the components would need to be restrained or supported in accordance with the component restraint basis defined in UFSAR Section 3.6A.2.3. UFSAR Section 3.6A.2.1 defines high-energy systems as systems or portions of the systems in which the maximum system operating temperature exceeds 200 ºF or the maximum system operating pressure exceeds 275 psig during normal plant conditions. This UFSAR section also establishes the criteria that a given location would need to be identified as a HELB location.

UFSAR Table 3.6A-14 identifies the plant systems that are HELB systems. The following UFSAR tables identify the component locations for the systems listed in UFSAR Table 3.6A-14 that are currently HELB component locations for the analysis:

- Table 3.6A-18 for break locations in the Class 1 portions of the main steam system
- Table 3.6A-19 for break locations in the Class 1 portions of the FW system (including Class 1 residual heat removal [RHR] and reactor water clean-up [RWCU] injection piping to the FW system)
- Table 3.6A-20 for reactor recirculation and RHR suction piping
- Table 3.6A-21 for steam piping to the reactor core isolation cooling (RCIC) system turbine
- Table 3.6A-23 for RWCU piping
- Table 3.6A-24 for low-pressure core spray (LPCS) piping
- Table 3.6A-25 for high-pressure core spray (HPCS) piping
- Table 3.6A-26 for low-pressure coolant injection (LPCI) piping

These UFSAR tables identify the intermediate high-energy Class 1 component locations listed as HELB locations that were added to the list based on having CUF values in excess of 0.1. The design transients for the ASME Code Class 1 systems in the HELB analyses are defined in the following sections or tables of the UFSAR: (a) main steam system components in UFSAR Section 3.9.1.1.1.5, (b) recirculation system transients in UFSAR Section 3.9.1.1.1.6, and (c) remaining Class 1 piping components in UFSAR Table 3.9-1.

The staff noted that LRA Section 4.7.2 did not identify the high-energy piping systems in UFSAR Table 3.6A-14 that were within the scope of the TLAA and the Fatigue Monitoring Program's cycle counting activities. By letter dated May 24, 2012, the staff issued RAI 4.7.2-1 requesting the applicant provide this clarification.

In its response dated June 21, 2012, the applicant stated that:

(a) The HELB TLAAs apply to all piping that utilized the criteria of CUF <0.1 to eliminate consideration of a postulated break, which includes much of the piping described in Table 3.6A-14. However, this table does not provide the details necessary to precisely identify the piping that is included in these descriptions of high-energy lines. The detailed description of the postulated pipe break locations is provided in the text, tables, and figures of UFSAR Section 3.6 and the details on the break locations postulated for connected systems are provided in UFSAR Section 3.C, including a description of the 3-inch and smaller high-energy lines.

(b) A review of the HELB evaluations and the associated analyses of CUFs will be performed as an enhancement to the Fatigue Monitoring Program, which will identify the specific Class 1 systems and components within the scope of the Fatigue Monitoring Program's cycle counting activities. The applicant stated that it will use the results of this review to ensure that the necessary transient cycles are tracked and the appropriate fatigue usage is monitored for the Class 1 systems and components for which HELB TLAAs apply. This enhancement to the program will adequately manage the effects of metal fatigue on all the high-energy piping in UFSAR Table 3.6A-14 that have used the criteria of CUF <0.1 in HELB evaluations.

The staff noted that the applicant has already included an enhancement to its Fatigue Monitoring Program to perform a review of its CUF calculations to identify the specific high-energy Class 1 components that would need to be included within scope of the cycle counting activities. In addition, these cycle counting activities will be performed consistent with the design transients and cycle limits assumed in the CUF calculations for these components that determined a CUF less than 0.1. The staff confirmed that the applicant has included this enhancement to the Fatigue Monitoring Program in Commitment No. 10 and in LRA Section A.1.19.

The staff noted that using the Fatigue Monitoring Program for the HELB TLAA is relevant for those intermediate high-energy Class 1 component locations with CUF values that are less than or equal to a value of 0.1. For these locations, the staff finds that the Fatigue Monitoring Program is acceptable to disposition the HELB TLAA in accordance with 10 CFR 54.21(c)(1)(iii) because the implementation of the program will assess whether the accumulation of design basis transients will result in CUF values that are in excess of a value of design limit of 0.1. If the cumulative fatigue usage approaches this design limit the applicant will take action to amend its design basis to identify the affected ASME Code Class 1 components as additional HELB locations. The staff noted that actions may include the need to modify the design of the components to include pipe whip restraints or refinement of the fatigue analysis to demonstrate that the CUF value for the affected components still meets the design limit of 0.1.

Additionally, the Fatigue Monitoring Program for the HELB TLAA meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because: (a) the staff has confirmed that the applicant's Fatigue Monitoring Program (LRA AMP B.1.19) is an acceptable means for managing the effects of cumulative fatigue damage on the results of the HELB analyses, (b) it serves as an acceptable basis for determining whether additional Class 1 components need to be added as HELB locations based on the results of any updated CUF analyses performed on the components under the AMP, and (c) it demonstrates conformance with the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 on when Fatigue Monitoring Programs can be used to accept CUF-based TLAAs in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii). RAI 4.7.2-1 is resolved.

The staff evaluates the ability of the Fatigue Monitoring Program to manage the impacts of fatigue-related aging effects on the GGNS ASME Code Class 1 components (including those that are within the scope of the HELB TLAA) in SER Section 3.0.3.1.18.

4.7.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its HELB TLAA in LRA Section A.2.5.2. The staff reviewed the UFSAR supplement summary description consistent with SRP-LR 4.7.3.2, which states that the reviewer should verify that the applicant has provided information in its UFSAR supplement that includes a summary description of the evaluation of the TLAA and describes how the TLAA has been dispositioned for the period of extended operation.

The staff noted that the applicant's UFSAR supplement summary description for the HELB TLAA provided an accurate and sufficient discussion of the HELB TLAA based on the HELB design basis in UFSAR Section 3.6A.2 and the design transients for the high-energy Class 1 systems within the scope of the HELB analyses, which are defined in UFSAR Section 3.9. The staff also noted that the UFSAR supplement summary description for the HELB TLAA provided an acceptable summary of the applicant's basis for accepting the HELB TLAA in accordance with the criterion in 10 CFR 54.21(c)(1)(iii) and for using the Fatigue Monitoring Program to manage the fatigue-related effects of aging that are applicable to the intermediate, high-energy ASME Code Class 1 systems and components within the scope of HELB TLAA. Thus, the staff found that the applicant had included an acceptable UFSAR supplement summary description because, consistent with the criterion in SRP-LR Section 4.7.3.2, it had provided an adequate description of the TLAA consistent with the GGNS design basis and the basis for accepting the TLAA in accordance with 10 CFR 54.21(c)(1)(iii). Based on its review of the UFSAR supplement consistent with the guidance of SRP-LR Section 4.7.3.2, the staff concludes that the summary description of the applicant's actions to address the HELB TLAA is adequate.

4.7.2.4 Conclusion

On the basis of its review, the staff concludes that, the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the HELB locations 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 HELB TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Fluence Effects for the Reactor Vessel Internals

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 describes the applicant's TLAA for fluence effects for the RVI components. The LRA states that a design specification for the RVI components includes requirements beyond ASME Code design requirements for austenitic stainless steel base metal components exposed to greater than 1×10^{21} n/cm^2 (greater than 1 MeV) or weld metal greater than 5×10^{20} n/cm^2 (greater than 1 MeV). The applicant analyzed the fluence of the RVI components included in the design specification at EPU operating conditions for 60 years of plant life (54 EFPY) and determined the location-specific fluence levels. Specifically, the LRA states that those RVI components that are defined as RVI core support structure components were evaluated against the irradiation criteria in the design specification. The LRA states that the results of the evaluation show that the RVI core support structure components meet the design specification at EPU operating conditions for 54 EFPY. The applicant dispositioned the TLAA for fluence effects for the RVI components 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.

4.7.3.2 Staff Evaluation

The staff reviewed the applicant's analysis to address the effects of fluence on strain values and clamping loads for certain RVI components, and the corresponding disposition that the analysis has been projected to the end of the period of extended operation, consistent with SRP-LR Section 4.7.3.1.2. The SRP-LR states 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. The SRP-LR also states that the applicant may recalculate the analysis using a 60-year period to show that the acceptance criteria continue to be satisfied for the period of extended operation. In addition, the SRP-LR states that the applicant shall provide a sufficient description of the analysis and document the results of the reanalysis to show that it is satisfactory for the 60-year period.

The staff determined that LRA Section 4.7.3 does not provide a sufficient description of the analysis and, therefore, the staff could not evaluate the adequacy of the TLAA. By letter dated June 27, 2012, the staff issued RAI 4.7.3-1 requesting the applicant to clarify the scope of the analysis by justifying why only the RVI core support structure components were evaluated against the irradiation criteria in the design specification. The staff also requested that the applicant (a) identify the 40-year fluence levels of the RVI components, (b) identify and justify the projected 60-year fluence levels for these components, and (c) identify the design requirements from the design specification and the ASME Code.

The applicant responded to RAI 4.7.3-1 by letter dated July 25, 2012. Regarding the staff's request to justify why only the RVI core support structure components were evaluated, the applicant explained that the provision to evaluate the fluence effects on these components is from a vendor design specification. The applicant also stated that non-core-support-structure bolting components were also evaluated as part of the TLAA. The applicant provided a table in the response identifying the specific components included in the analysis. The staff reviewed the response and determined that it adequately clarifies the scope of the TLAA because it specifically identifies each of the RVI components that are addressed in the analysis.

As part of the response to RAI 4.7.3-1, the applicant also provided the 40- and 60-year fluence values for each RVI component within the scope of the analysis. However, for several components, the applicant later determined that the fluence values were incorrect and submitted corrected values for these components by letters dated September 4, 2012, and October 15, 2012. The staff reviewed this information and determined that it adequately responds to the staff's request to provide the 40-year fluence levels and the projected 60-year fluence levels.

As another part of its response to RAI 4.7.3-1, the applicant stated that the 60-year fluence levels were calculated in accordance with the NRC-approved fluence methodology in topical report NEDC-32983P-A, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations," Revision 2 (GE methodology). The staff reviewed this justification with the applicant's July 25, 2012, response to RAI 4.2.1-2, which states that the GE methodology was incorporated into the CLB during EPU license amendment approval. SRP-LR Section 4.7.3.1.2 states that the applicable analysis technique can be the one that is in effect in the CLB at the time when the LRA is filed. However, it was not clear to the staff whether the applicant's analysis technique (i.e., use of the GE methodology) was consistent with the CLB when the LRA was filed because the EPU license amendment was approved after the applicant submitted the LRA. Nevertheless, the applicant used the GE methodology to calculate both the pre-EPU fluence and post-EPU fluence values for the RVI components in the TLAA through the period of extended operation. Therefore, by letter dated November 20, 2012, the staff issued RAI 4.7.3-1a, Part b, requesting that the applicant justify use of the GE methodology for calculating the pre-EPU fluence for the RVI components.

In addition, as part of the response to RAI 4.7.3-1 regarding identification of the applicable design requirements from the design specification and the ASME Code, the applicant stated that the core shroud was built to the stress criteria of ASME Code Section III, "Rules for Construction of Nuclear Facility Components," Subsection NG, "Core Support Structures," but clarified that the ASME Code Section III does not have specific requirements for evaluating the irradiation effects on RVI. The applicant explained that the impact of an increased fast fluence exposure on the integrity of the components is an increase in the yield and tensile strengths of the materials used to fabricate the components. The applicant therefore concluded that an increased fluence exposure on the components has no impact on the stress qualification. The applicant also explained that fast fluence can cause stress relaxation in those RVI components that are used in fastened mechanical connections, such as bolted RVI assemblies. The applicant stated that the effects of stress relaxation were therefore evaluated for those RVI core-support-structure and non-core-support-structure bolting components that were within the scope of the TLAA. The staff reviewed the response and determined that, although it clarifies that the applicable design requirements are not from the ASME Code, it does not provide the requested fluence-based design requirements for the components. Therefore, the staff noted that the applicant did not sufficiently demonstrate that the results of the re-analysis would be satisfactory for 60 years of plant operation. In RAI 4.7.3-1a, Part a., the staff again requested the applicant to provide the applicable design requirements for each RVI component that was included and analyzed in the TLAA and to show that these requirements are met as a result of the re-analysis of fluence effects through the proposed 60 years of plant operation.

The applicant responded to RAI 4.7.3-1a, Part a., by letter dated January 18, 2013. In its response, the applicant explained that the applicable design requirements establish maximum strain levels for non-fastened RVI base metal components, maximum stress levels for RVI weld components, and minimum preload requirements (clamping load requirements) for RVI threaded fasteners (bolting). The applicant also stated that the stress levels for RVI weld components are not impacted by neutron fluence. For the other RVI base metal component types, the applicant stated that the design requirements of the components would not receive any special considerations in the ASME Code as long as the projected neutron fluence values for the components at 54 EFPY are projected to remain lower than thresholds for inducing the applicable aging effects in the components (i.e., changes in dimension due to strain or component elongation for RVI non-fastened base metal components and loss of preload due to stress relaxation in RVI bolting).

The applicant identified that the applicable fluence threshold is defined as $1x10^{21}$ nvt (E > 1.0 MeV) for RVI base metal components made from stainless steel materials. The applicant also provided and defined the applicable ASME Code design requirements for calculating the allowable strains in these non-fastened RVI base metal components or the allowable stresses for RVI weld components. For RVI threaded fasteners (i.e., bolting), the applicant stated that the applied preloads (i.e., clamping loads) for the bolts would need to exceed the minimum preloads in the Code requirements needed for structural integrity of the fastened assemblies.

The applicant also provided a proprietary table (Enclosure 1 in ADAMS Accession No. ML13022A475) that provided the calculated strains and allowable strains for the RVI base metal components and the applied clamping and clamping allowables for RVI bolting components. For components whose projected neutron fluence (at 54 EFPY) was projected to exceed the applicable fluence threshold, the staff reviewed the proprietary table to verify that: (a) the operational strains for non-fastened RVI base metal components were within the maximum allowable strain criteria for the components, and (b) the applied preloads for RVI bolting components were greater than the minimum required preload needed for structural integrity of the fastened RVI assemblies. For RVI non-fastened base-metal components, the staff verified that the calculated strains for the components were lower than the limiting maximum allowable strain values for the components, as calculated using the applicable ASME strain equation given in the RAI response. Similarly for RVI bolting components, the staff verified that the preloads applied to the components were greater than the minimum required preloads needed for structural integrity of the bolted assemblies.

Based on its review and as described above, the staff finds the applicant's response to RAI 4.7.3-1a, Part a, acceptable.

By letter dated December 18, 2012, the staff issued RAI 4.7.3-1a, Part b, requesting that the applicant justify use of the GEH method for calculating fluence values for the reactor vessel internals (RVIs). Subsequently, the staff noted that the license amendment dated August 18, 2015 approved use of the MPM single fluence method, which became the GGNS CLB methodology for fluence evaluation, as described in SER Section 4.2.1.2. This license amendment is based on the staff's acceptance of the MPM fluence method which adheres to RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," for the RPV as documented in Section 4.2.1 of this safety evaluation report. In its review, the staff confirmed that specific fluence method modeling options important for RVI fluence calculations were appropriate and consistent with the relevant guidance in RG 1.190. Specifically, the staff confirmed the appropriateness of the following: (1) spatial mesh resolution in the axial direction, (2) angular quadrature order with supporting sensitivity studies, (3) anisotropic scattering treatment with respect to scattering cross-sections, (4) specification of a high resolution three-dimensional neutron source, specifically in the axial direction, (5) detailed three-dimensional water density distribution modeled in the core region, and (6) modeling of material regions between the active fuel region and the model boundaries. The staff also confirmed that fluence method uncertainties associated with RVIs were appropriately determined.

The staff finds the fluence calculations for the RVIs acceptable because (1) the applicant used appropriate modeling options for RVI fluence calculations using the MPM method which is consistent with RG 1.190; and (2) fluence method uncertainties associated with RVIs were appropriately determined. The staff's concern described in RAI 4.2.1-2c, Part 5(b) and RAI 4.7.3-1a, Part b regarding RVI fluence calculations is resolved.

In its response dated July 29, 2015 to RAI 4.2.1-2c, Part 5(b), the applicant also addressed whether the updated RVI fluence values calculated using the staff-approved MPM method affect the TLAA regarding the fluence effects on RVIs. The applicant stated that no change to LRA Section 4.7.3 is necessary because the RVIs with the updated 54-EFPY fluence values, calculated using the MPM fluence method, continue to meet the design specification. By letter dated April 4, 2016, the applicant also provided an updated proprietary table that describes the calculated strains and maximum allowable strains for RVI components and the applied clamping loads and load allowable clamping for RVI bolting components. The staff noted that the calculated strains and clamping loads met the acceptance criteria in accordance with the design specification.

Therefore, based on this review, the staff finds that the applicant has appropriately demonstrated that this TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(ii) because: (a) the applicant has adequately explained how the evaluation of neutron fluence factors into the design calculations for RVI components at the facility, (b) the applicant has demonstrated that the neutron fluence projection basis for the RVI components is based on use of an acceptable neutron fluence methodology, and (c) the staff has verified that the applicant has appropriately projected the neutron fluence to the end of the period of extended operation (i.e., to 54 EFPY) and has demonstrated that the applicable strains or preload levels will meet the applicable design requirements for these parameters. RAI 4.7.3-1a, Parts a and b, are resolved and Open Item 4.2.1-1, as related to this TLAA, is closed.

4.7.3.3 UFSAR Supplement

LRA Section A.2.5.3 provides the UFSAR supplement summarizing the TLAA for fluence effects for the RVI. The staff reviewed LRA Section A.2.5.3 consistent with SRP-LR Section 4.7.3.2, which states that the following is to be confirmed: (a) that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA, and (b) that each such summary description is appropriate such that later changes can be controlled by 10 CFR 50.59. The SRP-LR also states that the description should contain information that the TLAA has been dispositioned for the period of extended operation. The staff verified that the UFSAR supplement summary description provides an adequate summary of the fluence effects for reactor vessel internals analysis and the basis for accepting this TLAA in accordance with the requirement in 10 CFR 54.21(c)(1)(ii).

Based on its review of the UFSAR supplement, the staff finds it 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 the Fluence Effects for Reactor Vessel Internals Analysis and the applicant's basis for projecting this TLAA to the end of the period of extended operation, as required by 10 CFR 54.21(d).

4.7.3.4 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 Fluence Effects for Reactor Vessel Internals Analysis has been projected to the end of the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.4 Fatigue Analysis of Cranes

4.7.4.1 Summary of Technical Information in the Application

As added by letter dated October 2, 2012, in response to RAI 4.1-2a, LRA Section 4.7.4.1 describes the applicant's TLAA for the fatigue analysis of cranes. The applicant stated that the cranes designed to CMAA-70, have cycles specified as part of their design analysis. The applicant determined that the spent fuel cask crane, new fuel handling crane, and polar crane include CMAA-70 in their design specifications, and that the number of load cycles a crane is qualified for under CMAA-70 is 100,000 cycles. The applicant also stated that the expected number of lifts is well below the value specified in CMAA-70. The applicant further stated that cranes that were designed to CMAA-70 were evaluated as TLAAs.

The applicant dispositioned the TLAA for the spent fuel cask crane, new fuel handling crane, and polar crane in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the spent fuel cask crane, new fuel handling crane, and polar crane, and the corresponding disposition of 10 CFR 54.21(c)(1)(i) consistent with 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.

<u>Spent Fuel Cask Crane</u>. The staff reviewed UFSAR Section 9.1.4, "Fuel Handling System," and noted that the primary purpose of the spent fuel cask crane is to facilitate onsite handling of the fuel cask. The spent fuel cask crane is a 150-ton capacity crane designed to handle a fuel shipping cask or dry fuel storage transfer cask weighing approximately 125 tons. The staff also

reviewed the table in LRA Section 4.7.4.1, as amended by letter dated October 2, 2012, and noted that the applicant has estimated 250 lifts per operating cycle, and an estimated 37 operating cycles through the period of extended operation. The applicant's total estimated number of lifts through the period of extended operation is 9,250, which is significantly less than the 100,000 permissible cycles for which the crane was designed and, therefore, is acceptable.

New Fuel Handling Crane. The staff reviewed UFSAR Section 9.1.4, "Fuel Handling System," and noted that the new fuel bridge crane is a 5-ton capacity crane which handles new fuel from the time it arrives in the fuel handling area until it is placed in the fuel preparation machine. The staff also reviewed the table in LRA Section 4.7.4.1, as amended by letter dated October 2, 2012, and noted that the applicant has estimated 720 lifts per operating cycle, and an estimated 37 operating cycles through the period of extended operation. The applicant's total estimated number of lifts through the period of extended operation is 26,640, which is significantly less than the 100,000 permissible cycles for which the crane was designed and, therefore, is acceptable.

Polar Crane. The staff reviewed UFSAR Section 9.1.4, "Fuel Handling System," and noted that the polar crane is designed as seismic Category I equipment. The main hoisting equipment is designed for a 125-ton capacity, and the auxiliary hoist is designed for a 35-ton capacity. UFSAR Section 9.1.4.2.2.1 states that the containment polar crane is used to move all of the major components (RV head, shroud head and separator, and dryer assembly), as required by operations. The staff also reviewed the table in LRA Section 4.7.4.1, as amended by letter dated October 2, 2012, and noted that the applicant has estimated 200 lifts per operating cycle, and an estimated 37 operating cycles through the period of extended operation. The applicant's total estimated number of lifts through the period of extended operation is 7,400, which is significantly less than the 100,000 permissible cycles for which the crane was designed and, therefore, is acceptable.

Based on its review, the staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the spent fuel cask crane, new fuel handling crane, and polar crane remain valid for the period of extended operation.

4.7.4.3 UFSAR Supplement

LRA Section A.2.5.4, as amended by letter dated October 2, 2012, provides the UFSAR supplement summarizing the fatigue analysis of cranes. The staff reviewed LRA Section A.2.5.4 consistent with SRP-LR Section 4.7.3.2, which states that the applicant has provided 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, as amended by letter dated October 2, 2012, 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 fatigue analyses of the spent fuel cask crane, new fuel handling crane, and polar crane, as required by 10 CFR 54.21(d).

4.7.4.4 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 fatigue analyses for the spent fuel cask crane, new fuel handling crane, and polar crane 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).

4.8 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 the applicant has demonstrated that: (1) the TLAAs will 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) the effects of aging on 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, as required by 10 CFR 54.21(c)(2), that no plant-specific, TLAA-based exemptions are in effect.

With regard to these matters, the staff concludes that there is reasonable assurance that the activities authorized by the renewed license 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, Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” of the *Code of Federal Regulations*, the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for Grand Gulf Nuclear Station, Unit 1 (GGNS). The ACRS Subcommittee on Plant License Renewal continued its detailed review of the LRA after this safety evaluation report (SER) was issued. Entergy Operations, Inc. (Entergy or the applicant) and the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff) meet with the Subcommittee in May 2016, and will meet with the full Committee to discuss issues associated with the review of the LRA.

During the 637th meeting of the ACRS held October 6, 2016, the ACRS completed its review of the GGNS LRA and the staff’s SER. The ACRS documented its findings in a letter to the Commission dated October 14, 2016. A copy of this letter is provided in this section.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

October 14, 2016

The Honorable Stephen G. Burns
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION OF THE GRAND GULF NUCLEAR STATION, UNIT 1

Dear Chairman Burns:

During the 637th meeting of the Advisory Committee on Reactor Safeguards (ACRS), October 6-7, 2016, we completed our review of the license renewal application for the Grand Gulf Nuclear Station, Unit 1 (GGNS) and the final safety evaluation report (SER) prepared by the NRC staff. Our Subcommittee on Plant License Renewal reviewed this matter during a meeting on May 4, 2016. During these reviews, we had the benefit of discussions with representatives of the staff and Entergy Operations, Inc. (Entergy or the applicant). We also had the benefit of the referenced documents. This report fulfills the requirement of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

CONCLUSION AND RECOMMENDATION

1. The programs established and committed to by Entergy to manage age-related degradation provide reasonable assurance that Grand Gulf Nuclear Station, Unit 1 can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public.

2. Entergy's application for renewal of the operating license for Grand Gulf Nuclear Station, Unit 1, should be approved.

BACKGROUND

GGNS is located about 25 miles southwest of Vicksburg, MS. The NRC issued the GGNS construction permit on September 4, 1974, and operating license on November 1, 1984. GGNS is a boiling water reactor design, a GE BWR 6. General Electric supplied the nuclear steam supply system and Allis-Chalmers Power Systems furnished the turbine generator set. The Mark 3 BWR containment is a steel-lined reinforced concrete structure designed by Bechtel Power Corporation. The GGNS licensed power output is 4,408 megawatts thermal.

In this application, Entergy requests renewal of their operating license for a period of 20 years beyond the current expiration date of midnight, November 1, 2024.

DISCUSSION

In its final SER, dated September 2016, the staff documented its review of the license renewal application and other information submitted by the applicant, and obtained through staff audits and inspections at the plant site. The staff reviewed the completeness of the identification of structures, systems, and components (SSCs) that are within the scope of license renewal. The staff also reviewed the integrated plant assessment process; the identification of plausible aging mechanisms associated with passive, long-lived components; the adequacy of the Aging Management Programs (AMPs); and the identification and assessment of Time-Limited Aging Analyses (TLAAs) requiring review.

The application demonstrates consistency with the Generic Aging Lessons Learned (GALL) Report (NUREG-1801, Revision 2) and documents and justifies deviations to the specified approaches in that report. Entergy will implement 44 AMPs for license renewal, comprised of 34 existing programs and 10 new programs. Sixteen of the 44 AMPs are consistent with the GALL Report without enhancements or exceptions. Twenty AMPs are consistent with enhancements. Three AMPs are consistent with exceptions. Three AMPs are consistent with enhancements and exceptions. Two AMPs, Periodic Surveillance and Preventive Maintenance and 115 kV Inaccessible Transmission Cable, are plant-specific.

The license renewal application includes six programs with exceptions to the GALL Report. We reviewed these exceptions (BWR Stress Corrosion Cracking, Fatigue Monitoring, Flow-Accelerated Corrosion, Reactor Head Closure Studs, Reactor Vessel Surveillance, and Containment Leak Rate). We conclude that the six programs with GALL exceptions are acceptable.

The staff conducted license renewal audits and performed a license renewal inspection at GGNS. The audits verified the appropriateness of the scoping and screening methodology for AMPs, the appropriateness of the aging management review, and the acceptability of the TLAAs. The license renewal inspection verified that the license renewal requirements are implemented appropriately. Both the inspection, and the report of that inspection, are thorough. Based on the audits, the inspection, and reviews related to this license renewal application, the staff concluded in the final SER that the proposed activities will manage the effects of aging of SSCs identified in the application and that the intended functions of these SSCs will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In January 2013, the staff issued an SER with four open items. The open items were resolved during the intervening three years. Those open items pertained to One-Time Inspection – Small-Bore Piping, Service Water Integrity, Operating Experience for Aging Management Programs, and Reactor Vessel Fluence. A discussion of the resolution of these items follows.

One-Time Inspection – Small-Bore Piping

The GGNS operating experience review of the previous 10 years of condition reports did not fully demonstrate consistency with GALL Report AMP XI.M35, One-Time Inspection of ASME Code Class 1 Small-Bore Piping. After the applicant reviewed plant-specific operating experience covering the full operating history of the plant and identified no instances of age-related cracking of ASME Code Class 1 small-bore piping, the staff determined that the applicant had demonstrated applicability of GALL Report AMP XI.M35 to GGNS.

Service Water Integrity

Recent GGNS plant-specific operating experience condition reports discuss minor erosion to a valve flange connection in the standby service water system. The applicant revised LRA Sections A.1.41 and B.1.41 to state that the Service Water Integrity Program also includes inspections for loss of material due to erosion and included a new enhancement to revise program documents to include inspections for this aging mechanism. The applicant also stated that discrepancies were identified in the GGNS-MS-46 database, and this condition had been entered into its corrective action program

Operating Experience for Aging Management Programs

The staff had determined that the applicant's programmatic activities for the ongoing review of operating experience were consistent with the guidance in SRP-LR Section A.4.2, as established in LR-ISG-2011-05, with the exception of four activities. Based on its review of additional information provided by the applicant, the staff found that three of those activities are consistent with the guidance: (1) identification of age-related operating experience, (2) evaluation of AMP implementation results, and (3) the content of its personnel training.

The staff found that the applicant's activities associated with the fourth activity, operating experience reporting, are not consistent with the guidance. However, the staff determined that this inconsistency is an acceptable departure from the guidance because the programs provide 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) the enhancement of AMPs 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.

Reactor Vessel Fluence

SRP-LR Section 4.2 indicates that the applicant's fluence analysis should identify (a) the neutron fluence for the reactor vessel at the expiration of the license renewal period; (b) the staff-approved methodology used to determine the neutron fluence; and (c) whether the method follows the guidance in RG 1.190. In its review, the staff identified discrepancies, noted incomplete documentation of technical bases, and found that the methods used were inconsistent with RG 1.190. The issues were complex. In 2012 and 2013, the staff issued an initial series of RAIs and received responses from the applicant. In August 2013, the staff issued a comprehensive RAI that suggested alternative paths to resolve the issues. In a series of responses between September 2013 and July 2015, the applicant successfully explained differences in results for the two methods originally used; revised the fluence projections for its neutron embrittlement TLAAs using a single, improved, NRC-approved method that showed good agreement with GGNS dosimetry measurements.

During the time between our subcommittee meeting and our review, the applicant submitted additional clarification of the GGNS containment leak rate program, detailing two exceptions to the program described in NUREG-1801, Section XI, S4. The staff found that, with these exceptions, the revised AMP is adequate to manage the effects of aging for SSCs within the scope of the containment leak rate program.

We agree with the staff that there are no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) that preclude renewal of the operating license for GGNS. The programs established and committed to by Entergy provide reasonable assurance that GGNS can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public. The Entergy application for renewal of the operating license for Grand Gulf Nuclear Station, Unit 1 should be approved.

Sincerely,

/RA/

Dennis C. Bley
Chairman

REFERENCES

1. Entergy Operations, Inc., "Grand Gulf Nuclear Station, Unit 1, License Renewal Application," dated October 28, 2011(ML11308A101).

2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1," dated September 2016 (ML16250A838).

3. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report with Open items Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1," dated April 2016 (ML16090A252).

4. U.S. Nuclear Regulatory Commission, "Scoping and Screening Methodology Audit Report Regarding the Grand Gulf Nuclear Station, Unit 1 License Renewal Application," dated June 20, 2012 (ML12165A387).

5. U.S. Nuclear Regulatory Commission, "NRC Aging Management Programs Audit Report Regarding the Grand Gulf Nuclear Station,' Unit 1, dated June 8, 2012 (ML12137A290).

6. U.S. Nuclear Regulatory Commission, “Grand Gulf Nuclear Station - NRC License Renewal Inspection Report 05000416/2012007,” dated September 24, 2012 (ML ML12268A365).

7. U.S. Nuclear Regulatory Commission, NRC NUREG-1800, Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), dated December 2010 (ML103409036).

8. U.S. Nuclear Regulatory Commission, NRC NUREG-1801, Revision 2, “Generic Aging Lessons Learned (GALL) Report,” dated December 2010 (ML103409041).

9. U.S. Nuclear Regulatory Commission, NRC Regulatory Guide-1.188, Revision 1, “Standard Format and Content for Application to Renew Nuclear Power Plant Operating Licenses,” dated September 2005 (ML082950585).

10. Entergy Operations, Inc., “Grand Gulf Nuclear Station, Unit 1, License Renewal Application 2012 Annual Update,” dated August 15, 2012 (ML12229A582).

11. Entergy Operations, Inc., “Grand Gulf Nuclear Station, Unit 1, License Renewal Application 2013 Annual Update,” dated October 25, 2013 (ML13302A598).

12. Entergy Operations, Inc., “Grand Gulf Nuclear Station, Unit 1, License Renewal Application 2014 Annual Update,” dated October 27, 2014 (ML14301A102).

13. Entergy Operations, Inc., “Grand Gulf Nuclear Station, Unit 1, License Renewal Application 2015 Annual Update,” dated December 10, 2015 (ML15344A283).

14. Entergy Operations, Inc., “Clarification of Grand Gulf Nuclear Station Containment Leak Rate Program Description Grand Gulf Nuclear Station, Unit 1 Docket No. 50-416,” dated September 23, 2016 (ML16267A400).

15. Entergy Operations, Inc., “Additional Clarification of the Grand Gulf Nuclear Station Containment Leak Rate Program Description Grand Gulf Nuclear Station, Unit 1 Docket No. 50-416,” dated October 3, 2016 (ML16277A573).

16. U.S. Nuclear Regulatory Commission, “Staff SER Update to Section 3.0.3.1.14 Containment Leak Rate,” dated October 5, 2016 (ML16279A517).

17. U.S. Nuclear Regulatory Commission, RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” dated March 2001 (ML010890301).

SECTION 6

CONCLUSION

The staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Grand Gulf Nuclear Station, Unit 1 (GGNS), in accordance with NRC regulations and NUREG-1800, Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated December 2010. Title 10 of the *Code of Federal Regulations* (10 CFR) 54.29 sets the standards for issuance of a renewed license.

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

GRAND GULF NUCLEAR STATION, UNIT 1, LICENSE RENEWAL COMMITMENTS

During the review of the Grand Gulf Nuclear Station, Unit 1 (GGNS) license renewal application (LRA) by the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff), Entergy Operations, Inc., (Entergy 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: GRAND GULF LICENSE RENEWAL COMMITMENTS

Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
1	Implement the 115 kilovolt (KV) Inaccessible Transmission Cable Program for Grand Gulf Nuclear Station (GGNS) as described in License Renewal Application (LRA) Section B.1.1	B.1.1	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096
2	Implement the Aboveground Metallic Tanks Program for GGNS as described in LRA Section B.1.2	B.1.2	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096
3	Enhance the Bolting Integrity Program for GGNS to clarify the prohibition on use of lubricants containing MoS_2 for bolting, and to specify that proper gasket compression will be visually verified following assembly. Enhance the Bolting Integrity Program to include consideration of the guidance applicable for pressure boundary bolting in Regulatory Guide (NUREG) 1339, Electric Power Research Institute (EPRI) NP-5769, and EPRI TR-104213. Enhance the Bolting Integrity Program to include volumetric examination per American Society of Mechanical Engineers (ASME) Code Section IX, Table IWB-2500-1, Examination Category B-G-1, for high-strength closure bolting regardless of code classification.	B.1.3	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096
4	Enhance the Boraflex Monitoring Program for GGNS to perform periodic surveillances of the boraflex neutron absorbing material in the spent fuel pool and upper containment pool at least once every 5 years using Boron-10 Areal Density Gage for Evaluating Racks (BADGER) testing. RACKLIFE analysis will continue to be performed each cycle. This analysis will include a comparison of the RACKLIFE predicted silica to the plant measured silica. This comparison will determine if adjustments to the RACKLIFE loss coefficient are merited. The analysis will include projections to the next planned RACKLIFE analysis date to ensure current Region I storage locations will not need to be reclassified as Region II storage locations in the analysis interval.	B.1.4	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00077 GNRO-2013/00096

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS

Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
5	Implement the Buried Piping and Tanks Inspection Program for GGNS as described in LRA Section B.1.5. Soil testing will be performed at two locations near the stainless steel condensate storage system piping that is subject to aging management review. Measured parameters will include soil resistivity, bacteria, pH, moisture, chlorides and redox potential. If the soil is determined to be corrosive then the number of inspections will be increased from one to two prior to and during the period of extended operation.	B.1.5	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2012/00089 GNRO-2013/00096
6	Enhance the Boiling Water Reactor (BWR) Vessel Internals Program for GGNS as follows. Evaluate the susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of CASS, X-750 alloy, precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel), and martensitic stainless steel (e.g., 403, 410 and 431 steel). This evaluation will include a plant-specific identification of the reactor vessel internals components made of these materials. Inspect portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions). The inspections will use an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within 5 years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of reinspection will be justified based on fracture toughness properties appropriate for the condition of the component. The sample size for the initial inspection of susceptible components will be 100 percent of the accessible component population, excluding components that may be in compression during normal operations.	B.1.11	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00137 GNRO-2013/00096

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS

Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
7	Enhance the Compressed Air Monitoring Program for GGNS to apply a consideration of the guidance of ASME OM-S/G-1998, Part 17; ANSI/ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147 to the limits specified for air system contaminants. Enhance the Compressed Air Monitoring Program to include periodic and opportunistic inspections of accessible internal surfaces of piping, compressors, dryers, aftercoolers, and filters to apply consideration of the guidance of ASME OM-S/G-1998, Part 17 for inspection frequency and inspection methods of these components in the following compressed air systems. • Automatic Depressurization System (ADS) air • Division 1 Diesel Generator Starting Air (D1DGSA) • Division 2 Diesel Generator Starting Air (D2DGSA) • Division 3 Diesel Generator Starting Air (D3DGSA), also known as the HPCS Diesel Generator • Instrument Air (IA)	B.1.12	Prior to May 1, 2014	GNRO-2011/00093 GNRO-2013/00096
8	Enhance the Diesel Fuel Monitoring Program to include a 10-year periodic cleaning and internal inspection of the fire water pump diesel fuel oil tanks, the diesel fuel oil day tanks for Divisions I, II, III, and the diesel fuel oil drip tanks for Divisions I, II. These cleanings and internal inspections will be performed at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals. If visual inspection is not possible, a volumetric inspection will be performed. Enhance the Diesel Fuel Monitoring Program to include a volumetric examination of affected areas of the diesel fuel tanks if evidence of degradation is observed during visual inspection. The scope of this enhancement includes the diesel fuel oil day tanks (Divisions I, II, III), the diesel fuel oil storage tanks (Divisions I, II, III), the diesel fuel oil drip tanks (Divisions I, II), and the diesel fire pump fuel oil storage tanks, and is applicable to the inspections performed during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals.	B.1.16	Prior to May 1, 2014, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS

Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
9	Enhance the External Surfaces Monitoring Program to include instructions for monitoring of the aging effects for flexible polymeric components through manual or physical manipulation of the material, including a sample size for manipulation of at least 10 percent of available surface area. Enhance the External Surfaces Monitoring Program as follows. Underground components within the scope of this program will be clearly identified in program documents. Instructions will be provided for inspecting all underground components within the scope of this program during each 5-year period, beginning 10 years prior to entering the period of extended operation. Revise External Surfaces Monitoring Program procedures to specify the following for insulated components. a. Periodic representative inspections will be conducted during each 10-year period during the period of extended operation. b. For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of the component surface. Inspections will include a minimum of 20 percent of the inscope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-ft axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-ft axial length sections and individual components for each material type. c. Inspection locations will be selected based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for longer periods of time below the dew point. Subsequent inspections can be limited to an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.	B.1.18	Prior to May 1, 2014, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00021 GNRO-2013/00096 GNRO-2014/00030

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS				
Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
9 (cont.)	d. No loss of material due to general, pitting, or crevice corrosion beyond that which could have been present during initial construction, and e. No evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of other types of insulation. These inspections will not be credited toward the inspection quantities for other types of insulation.			
10	Enhance the Fatigue Monitoring Program to monitor and track all critical thermal and pressure transients for all components that have been identified to have a fatigue Time Limited Aging Analysis (TLAA). Enhance the Fatigue Monitoring Program to perform a review of the GGNS high-energy line break analyses and the corresponding tracking of associated cumulative usage factors to ensure the GGNS program adequately manages fatigue usage for these locations. Fatigue usage calculations that consider the effects of the reactor water environment will be developed for a set of sample reactor coolant system components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found to be more limiting than those considered in NUREG/CR-6260. F_{en} factors will be determined using the formulae sets listed in Section 4.3.3. If necessary following this analysis, revised cycle limits will be incorporated into the Fatigue Monitoring Program documentation.	B.1.19	Prior to November 1, 2022	GNRO-2011/00093 GNRO-2012/00063 GNRO-2013/00096

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS				
Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
10 (cont.)	Enhance the Fatigue Monitoring Program to provide updates of the fatigue usage calculations on an as needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components have been modified. The program revision will include providing for the consideration of the recirculation pump fatigue analysis exemption validity if cycles that were input into the exemption evaluation exceed their limits.			
11	Enhance the Fire Protection Program to require visual inspections of the Halon/CO_2 fire suppression system at least once every fuel cycle to examine for signs of corrosion. Enhance the Fire Protection Program to require visual inspections of fire damper framing at least once every fuel cycle to check for signs of degradation. Enhance the Fire Protection Program to require visual inspection of concrete curbs, manways, hatches, manhole covers, hatch covers, and roof slabs at least once every fuel cycle to confirm that aging effects are not occurring. Enhance the Fire Protection Program to require an external visual inspection of the CO_2 tank at least once every fuel cycle to examine for signs of corrosion.	B.1.20	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00042 GNRO-2013/00096
12	The Fire Water System Program will be enhanced as follows. Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with NFPA 25 (2011 Edition), Section 5.3.1. Revise Fire Water System program procedures to specify replacing any sprinkler that shows signs of leakage or corrosion. Revise Fire Water System Program procedures to perform a flow blockage evaluation if during main drain testing, the flowing pressure drops more than 10 percent from the flowing pressure observed during the original acceptance test or other previously performed tests at the same location. Revise Fire Water System Program procedures to ensure there is no flow blockage by visually inspecting the charcoal filter deluge fire water distribution piping when the charcoal is replaced.	B.1.21	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2012/00089 GNRO-2011/00093 GNRO-2013/00096 GNRO-2014/00030 GNRO-2014/00076 GNRO-2015/00034 GNRO-2015/00055 GNRO-2015/00079

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
12 (cont.)	Revise Fire Water System Program procedures to perform air flow testing to ensure there are no obstructions downstream of the deluge valves for control room fresh air, auxiliary building standby gas, containment cooling system, and containment vent charcoal filter units each refueling cycle. Revise Fire Water System Program procedures to include periodic internal inspections and documentation of any excessive accumulation of corrosion products appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer in the corrective action program and that follow-up volumetric wall thickness examination will be performed as part of the corrective action. Revise Fire Water System Program procedures to require internal inspections at the end of one fire main and the end of one branch line on two of the wet pipe systems in the auxiliary building, two of the wet pipe systems in the control building, and one wet pipe system in the fire pump house every 5 years. During each 5-year internal inspection period, inspect different wet pipe sprinklers such that internal inspections are performed on all of the wet pipe sprinkler systems in the auxiliary and control buildings every 15 years and in the fire pump house every 10 years. In the event internal obstructions are identified in a building wet pipe system, expand the number of inspections to include all of the wet pipe sprinkler systems in that building. Revise Fire Water System Program procedures to periodically open a flushing connection at the end of a main and remove a component such as a sprinkler toward the end of one branch line for piping associated with preaction, and dry pipe systems to perform a visual inspection in accordance with NFPA 25 (2011 Edition) Section 14.2.1. Revise Fire Water System Program procedures to inspect the normally dry fire suppression piping and piping components with a 10 CFR 54.4(a)(3) intended function that may be wetted to ensure that the piping does not collect water. In the event areas are identified that collect water, perform the following augmented tests and inspections to ensure that flow blockage have not occurred. 1. In each 5-year interval beginning with the 5-year period before the period of extended operation, perform either (a) a flow test or flush sufficient to detect potential flow blockage, or (b) visual inspections on 100 percent of the internal surface of piping segments that allow water to collect.			

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
12 (cont.)	In each 5-year interval during the period of extended operation, perform volumetric wall thickness inspections on 20 percent of the length of piping segments that allow water to collect. Data points are obtained to the extent that potential degraded conditions can be identified (e.g., general corrosion, microbiologically-influenced corrosion). The 20 percent of piping inspected in each 5-year interval should be in different locations than piping inspected in previous intervals. If the results of a 100 percent interval visual inspection are acceptable and the segment is not subsequently wetted, no further augmented tests or inspections are necessary. a. Revise Fire Water System Program procedures to include inspecting sprinklers in the overhead from the floor for signs of corrosion. b. Revise Fire Water System Program procedure to include periodic inspection of hose reels for degradation. c. Revise Fire Water System Program procedures to replace sprinklers that the tested sprinkler represents, if the tested sprinkler fails to meet the test acceptance criteria. d. Revise Fire Water System Program procedures to ensure the hydrant valve is opened fully and ensure the hydrant flows for not less than 1 minute during flow testing. e. Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following. 1. A review of at least two previous coating inspection results is performed prior to conducting a coating inspection. 2. The coating inspection report will include a list of locations identified with coating degradation including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to a subsequent inspection or repair opportunity.			

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Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
12 (cont.)	f. Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks at the frequency specified by NFPA 25 Section 9.2.6 to include the following. 1. Testing for possible voids beneath the tank. 2. Inspection of the vortex breaker. 3. Coating inspections and documentation, and review of inspection results are performed by qualified personnel. i. Individuals performing coating inspections are certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." ii. A nuclear coatings specialist qualified in accordance with ASTM D7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist," will evaluate inspection findings and prepare post-inspection reports. g. Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust, or flaking are identified during visual examination. 1. Adhesion testing endorsed by Regulatory Guide (RG) 1.54. 2. Dry film thickness measurements at random locations to determine overall coating thickness as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (2). 3. Nondestructive ultrasonic readings to evaluate the wall thickness where there is evidence of pitting or corrosion as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (3). 4. Spot wet-sponge tests to detect pinholes, cracks, or other compromises in the coating as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (4). 5. Test the tank bottom for metal loss or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (5).			

12 (cont.)	h. Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust, or flaking are identified during visual examination in accordance with NFPA 25 (2011 Edition), Section 9.2.6.4. 1. Lightly tapping and scraping the coating to determine the coating integrity. 2. Dry film thickness measurements at random locations to determine overall thickness of the coating. 3. Wet-sponge testing or dry film testing to identify holidays in the coating. 4. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations. 5. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria. i. Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination, or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating inspector, or the following actions are performed. 1. Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed. 2. Any delaminated or peeled coating is removed. 3. The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations. 4. The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area.			
12 (cont.)	5. Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements.			

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	6. An evaluation is performed to ensure downstream flow blockage is not a concern. 7. A follow-up inspection is scheduled to be performed within 2 years and every 2 years after that until the coating is repaired, replaced, or removed. j. Revise the Fire Water System Program procedures to include the following acceptance criteria for loss of coating integrity. 1. Indications of peeling and delamination are not acceptable. 2. Blisters are evaluated by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff limitations associated with the use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., reference ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints"). 3. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff limitations associated with the use of a particular standard. 4. Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material. 5. As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. 6. Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in plant specific design requirements specific to the coating/lining and substrate.			

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
12 (cont.)	k. Revise Fire Water System Program procedures to include a visual inspection of a representative number of locations on the interior surface of below-grade fire protection piping at a frequency of at least once every 10 years during the period of extended operation. A representative number is 20 percent of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. l. Revise Fire Water System Program procedures to inspect the strainers upstream of the deluge valves every 3 years. m. Revise Fire Water System Program procedures for flow testing, main drain testing, or internal inspection to specify an acceptance criterion of no debris observed (i.e., no corrosion products that are sufficient to obstruct flow or cause downstream components to become clogged.) n. Revise Fire Water System Program procedures to require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the corrective action program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains and branch lines, and the performance of a complete flushing program by qualified personnel. o. Revise Fire Water System Program procedures to require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access.			
13	Enhance the Flow-Accelerated Corrosion Program to revise program documentation to specify that downstream components are monitored closely to mitigate any increased wear when susceptible upstream components are replaced with resistant materials, such as high Cr material.	B.1.22	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
14	Enhance the Inservice Inspection – IWF Program to address inspections of accessible sliding surfaces. Enhance the Inservice Inspection – IWF Program to clarify that parameters monitored or inspected will include corrosion; deformation; misalignment of supports; missing, detached, or loosened support items; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Accessible areas of sliding surfaces will be monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support. Structural bolts will be monitored for corrosion and loss of integrity of bolted connections due to self-loosening and material conditions that can affect structural integrity. High-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa in sizes greater than 1 inch nominal diameter) susceptible to stress corrosion cracking (SCC) will be monitored for SCC. When a component support is found with minor age-related degradation, but still is evaluated as “acceptable for continued service” as defined in IWF-3400, the program owner may choose to repair the degraded component and substitute a randomly selected component that is more representative of the general population for it in subsequent inspections. Enhance the Inservice Inspection – IWF Program to clarify that detection of aging effects will include: a. Monitoring structural bolting (American Society for Testing Materials (ASTM) A-325, ASTM F1852, and ASTM A490 bolts) and anchor bolts for loss of material, loose or missing nuts, loss of preload and cracking of concrete around the anchor bolts. b. Volumetric examination comparable to that of ASME Code Section XI, Table IW8-2500-1, Examination Category 8-G-1 for high-strength structural bolting to detect cracking in addition to the VT-3 examination. This volumetric examination may be waived with adequate plant-specific justification.	B.1.24	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00105 GNRO-2012/00114 GNRO-2012/00055 GNRO-2013/00096

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
14 (cont.)	c. Identification of all component supports that contain high-strength bolting (actual measured yield greater than or equal to 150 ksi) in sizes greater than 1 inch nominal diameter. The extent of examination for support types that contain high-strength bolting will be as specified in ASME Code Section XI, Table IWF-2500-1. GGNS will examine high-strength structural bolting on the frequency specified in ASME Code Section XI, Table IWF-2500-1. Enhance the Inservice Inspection – IWF Program acceptance criteria to include the following as unacceptable conditions. a. Loss of material due to corrosion or wear, which reduces the load bearing capacity of the component support; b. Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; and c. Cracked or sheared bolts, including high-strength bolts, and anchors. Enhance the Inservice Inspection – IWF Program preventive action to include the following. Incorporate into plant procedures recommendations delineated in NUREG-1339, and Electric Power Research Institute (EPRI) NP-5769 and TR-1 04213 for high-strength structural bolting. These recommendations should address proper selection of bolting material, proper installation torque or tension, and the use of appropriate lubricants and sealants.			
15	Enhance the Inspection of Overhead Heavy Load and Light Load Handling Systems Program to include monitoring of rails in the rail system for the aging effect “wear,” and structural connections/bolting for loose or missing bolts, nuts, pins, or rivets. Additionally, the program will be clarified to include visual inspection of structural components and structural bolts for loss of material due to various mechanisms and structural bolting for loss of preload due to self-loosening. Enhance the Inspection of Overhead Heavy Load and Light Load Handling Systems Program acceptance criteria to state that any significant loss of material for structural components and structural bolts, and significant wear of rails in the rail system, is evaluated according to ASME B30.2 or other applicable industry standard in the ASME B30 series.	B.1.25	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096

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Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
16	Implement the Internal Surfaces in Miscellaneous Piping and Ducting Components Program as described in LRA Section B.1.26.	B.1.26	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096
17	Enhance the Masonry Wall Program to clarify that parameters monitored or inspected will include monitoring gaps between the supports and masonry walls that could potentially affect wall qualification. Enhance the Masonry Wall Program to clarify that detection of aging effects require masonry walls to be inspected every 5 years unless technical justification is provided to extend the inspection to a period not to exceed 10 years.	B.1.27	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096
18	Implement the Non-EO Cable Connections Program as described in LRA Section B.1.28	B.1.28	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096
19	Enhance the Non-Environmentally Qualified (Non-EQ) Inaccessible Power Cables (400V to 35kV) Program to include low-voltage (400V to 2kV) power cables. Enhance the Non-EQ Inaccessible Power Cables (400V to 35kV) Program to include condition-based inspections of manholes not automatically dewatered by a sump pump being performed following periods of heavy rain or potentially high water table conditions, as indicated by river level. Enhance the Non-EQ Inaccessible Power Cables (400V to 35kV) Program to clarify that the inspections will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and that dewatering/drainage systems (i.e., sump pumps) and associated alarms if applicable operate properly.	B.1.29	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096

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Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
20	Implement the Non-EQ Instrumentation Circuits Test Review Program as described in LRA Section B.1.30.	B.1.30	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096
21	Implement the Non-EQ Insulated Cables and Connections Program as described in LRA Section B.1.31.	B.1.31	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096
22	Enhance the Oil Analysis Program to provide a formalized analysis technique for particulate counting. Enhance the Oil Analysis Program to include piping and components within the main generator system (N41) with an internal environment of lube oil.	B.1.32	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096
23	Implement the One-Time Inspection Program as described in LRA Section B.1.33.	B.1.33	Within the 10 years prior to November 1, 2024	GNRO-2011/00093 GNRO-2013/00096
24	Implement the One-Time Inspection - Small Bore Piping Program as described in LRA Section B.1.34.	B.1.34	Within the 6 years prior to November 1, 2024	GNRO-2011/00093 GNRO-2013/00096
25	Enhance the Periodic Surveillance and Preventive Maintenance Program to revise program guidance documents as necessary to include all activities as described in LRA Section B.1.35.	B.1.35	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096 GNRO-2014/00076

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
26	Enhance the Protective Coating Program to include parameters monitored or inspected by the program per the guidance provided in ASTM 05163-08. Enhance the Protective Coating Monitoring and Maintenance Program to provide for inspection of coatings near sumps or screens associated with the Emergency Core Cooling System. Enhance the Protective Coating Program to include acceptance criteria per ASTM 05163-08.	B.1.36	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096
27	Ensure that the additional requirements of the ISP(E) specified in BWRVIP-86, Revision 1, including the conditions of the final NRC safety evaluation for BWRVIP-116 incorporated in BWRVIP-86, Revision 1, will be addressed before the period of extended operation. Ensure that new fluence projections through the period of extended operation and the latest vessel beltline ART Tables are provided to the BWRVIP prior to the period of extended operation.	B.1.38	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096 GNRO-2012/00081
28	Enhance the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plant Program to clarify that detection of aging effects will monitor accessible structures on a frequency not to exceed 5 years consistent with the frequency for implementing the requirements of RG 1.127. Enhance the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plant Program to perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every 5 years. Enhance the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plant Program acceptance criteria to include quantitative acceptance criteria for evaluation and acceptance based on the guidance provided in ACI 349.3R.	B.1.39	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2013/00096
29	Implement the Selective Leaching Program as described in LRA Section B.1.40.	B.1.40	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00096

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Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
30	Enhance the Structures Monitoring Program to clarify that the scope includes the following: a. In-scope structures and structural components. • Containment Building (GGN 2) • Control House - Switchyard • Culvert No.1 and drainage channel • Manholes and Ductbanks • Radioactive Waste Building Pipe Tunnel • Auxiliary Building (GGN2) • Turbine Building (GGN2) b. In-scope structural components • Anchor bolts • Anchorage / embedments • Base plates • Basin debris screen and grating • Battery racks • Beams, columns, floor slabs and interior walls • Cable tray and cable tray supports • Component and piping supports • Conduit and conduit supports • Containment sump liner and penetrations • Containment sump structures • Control room ceiling support system • Cooling tower drift eliminators • Cooling tower fill • CST/RWST retaining basin (wall) • Diesel fuel tank access tunnel slab • Drainage channel • Drywell electrical penetration sleeves • Drywell equipment hatch • Drywell floor slab (concrete) • Drywell head • Drywell head access manway • Drywell liner plate • Drywell mechanical penetration sleeves • Drywell personnel access lock	B.1.42	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00054 GNRO-2012/00074 GNRO-2012/00076 GNRO-2012/00095 GNRO-2012/00098 GNRO-2013/00096

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30 (cont.)	• Drywell wall (concrete) • Ductbanks • Electrical and instrument panels and enclosures • Equipment pads/foundations • Exterior walls • Fan stack grating • Fire proofing • Flood curbs • Flood retention materials (spare parts) • Flood, pressure and specialty doors • Floor slab • Foundations • HVAC duct supports • Instrument line supports • Instrument racks, frames and tubing trays • Interior walls • Main steam pipe tunnel • Manholes • Manways, hatches, manhole covers, and hatch covers • Metal siding • Missile shields • Monorails • Penetration sealant (flood, radiation) • Penetration sleeves (mechanical/electrical not penetrating primary containment boundary) • Pipe whip restraints • Pressure relief panels • Reactor pedestal • Reactor shield wall (steel portion) • Roof decking • Roof hatches • Roof membrane • Roof slabs • RPV pedestal sump liner and penetrations • Seals and gaskets (doors, manways and hatches) • Seismic isolation joint			

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
30 (cont.)	• Stairway, handrail, platform, grating, decking, and ladders • Structural bolting • Structural steel, beams columns, and plates • Sumps and sump liners • Support members: welds; bolted connections; support anchorages to building structure • Support pedestals • Transmission towers (see Note 1) • Upper containment pool floor and walls • Vents and louvers • Weir wall liner plate Note 1: The inspections of these structures may be performed by the transmission personnel. However, the results of the inspections will be provided to the GGNS Structures Monitoring Program owner for review. c. Clarify the term “significant degradation” to include “that could lead to loss of structural integrity.” d. Include guidance to perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every 5 years. Enhance the Structures Monitoring Program to clarify that parameters monitored or inspected include: a. inspection for missing nuts for structural connections. b. monitoring sliding/bearing surfaces such as Lubrite plates for loss of material due to wear or corrosion, debris, or dirt. The program will be enhanced to include monitoring elastomeric vibration isolators and structural sealants for cracking, loss of material, and hardening. c. Include periodically inspecting the leak chase system associated with the upper containment pool and spent fuel pool to ensure the tell-tales are free of significant blockage. The inspection will also inspect concrete surfaces for degradation where leakage has been observed, in accordance with this Program.			

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Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
30 (cont.)	Enhance the Structures Monitoring Program to clarify that detection of aging effects will: a. Include augmented inspections of vibration isolators by feel or touch to detect hardening if the vibration isolation function is suspect. b. Require inspections every 5 years for structures and structural components within the scope of license renewal. c. Require direct visual examinations when access is sufficient for the eye to be within 24 inches of the surface to be examined and at an angle of not less than 300 to the surface. Mirrors may be used to improve the angle of vision and accessibility in constricted areas. d. Specify that remote visual examination may be substituted for direct examination. For all remote visual examinations, optical aids such as telescopes, borescopes, fiber optics, cameras, or other suitable instruments may be used provided such systems have a resolution capability at least equivalent to that attainable by direct visual examination. e. Include instructions to augment the visual examinations of roof membranes, and seals and gaskets (doors, manways, and hatches) with physical manipulation of at least 10 percent of available surface area. Enhance the Structures Monitoring Program acceptance criteria by prescribing acceptance criteria based on information provided in industry codes, standards, and guidelines including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99 and ACI 349.3R-96. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria.			

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Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
31	Enhance the Water Chemistry Control – Closed Treated Water Program to provide a corrosion inhibitor for the engine jacket water on the engine-driven fire water pump diesel in accordance with industry guidelines and vendor recommendations. Enhance the Water Chemistry Control – Closed Treated Water Program to provide periodic flushing of the engine jacket water and cleaning of heat exchanger tubes for the engine-driven fire water pump diesel in accordance with industry guidelines and vendor recommendations. Enhance the Water Chemistry Control – Closed Treated Water Program to provide testing of the engine jacket water for the engine-driven fire water pump diesels at least annually. Enhance the Water Chemistry Control – Closed Treated Water Program to revise the water GNRO chemistry procedure for closed treated water systems to align the water chemistry control parameter limits with those of EPRI 1007820. Enhance the Water Chemistry Control – Closed Treated Water Program to conduct inspections whenever a boundary is opened for the following systems. • Drywell chilled water (DCW - system P72) • Plant chilled water (PCW - system P71) • Diesel generator cooling water subsystem for Division I and II standby diesel generators • Diesel engine jacket water for engine-driven fire water pump • Diesel generator cooling water subsystem for Division III (HPCS) diesel generator • Turbine building cooling water (TBCW - system P43) • Component cooling water (CCW - system P42)	B.1.44	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00049 GNRO-2013/00096

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31 (cont.)	These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, and other plant-specific inspection and personnel qualification procedures that are capable of detecting corrosion or cracking. Enhance the Water Chemistry Control – Closed Treated Water Program to inspect a representative sample of piping and components at a frequency of once every 10 years for the following systems. • Drywell chilled water (DCW - P72) • Plant chilled water (PCW - P71) • Diesel generator cooling water subsystem for Division I and II standby diesel generators • Diesel engine jacket water for engine-driven fire water pump • Diesel generator cooling water subsystem for Division III (HPCS) diesel generator • Turbine building cooling water (TBCW - P43) • Component cooling water (CCW - P42) Components inspected will be those with the highest likelihood of corrosion or cracking. A representative sample is 20% of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. The inspection methods will be in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that ensure the capability of detecting corrosion or cracking.			
32	Enhance the BWR CRD Return Line Nozzle Program to include inspection of the CRD return line nozzle inconel end cap to carbon steel safe end dissimilar metal weld once prior to the period of extended operation and every 10 years thereafter.	B.1.6	Prior to May 1, 2024, or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2012/00029 GNRO-2013/00096
33	Enhance the BWR Penetrations Program to include that site procedures which implement the guidelines of BWRVIP-47-A will be clarified to indicate that the guidelines of BWRVIP-47-A apply without exceptions.	B.1.8	Prior to May 1, 2024	GNRO-2012/00029 GNRO-2013/00096

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS				
Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
34	Deleted.			GNRO-2013/00028
35	The Service Water Integrity Program will be enhanced as follows. During the 10-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces of standby service water system components. Subsequent coating inspections will be performed based on inspection results as follows. i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and, if the redundant train has the same coating and turbulent flow is not present, then the redundant train need not be inspected during that inspection interval. ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval. iii. If the inspection results do not meet (i) and a coating specialist determines remediation is required, then the coated components can only be returned to service if the following actions are performed: (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determined by adhesion testing endorsed by RG 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, and (6) an evaluation is performed to ensure blockage downstream is not a concern, (7) a follow-up inspection is performed within 2 years and every 2 years until the coating is repaired, replaced, or removed.	B.1.41	Within the 10 years prior to November 1, 2024	GNRO-2013/00096 GNRO-2014/00030 GNRO-2014/00076 GNRO-2015/0 0055

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS

Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
35 (cont.)	Revise Service Water Integrity Program documents to include inspections for loss of material due to erosion. Revise Service Water Integrity Program documents to include visual inspections for loss of coating integrity during the 10-year period prior to the period of extended operation. Include provisions to specify subsequent coating inspections based on inspection results as follows. i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and the redundant train has the same coating and turbulent flow is not present, then the redundant train need not be inspected during that inspection interval. ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval. iii. If the inspection results do not meet (i) and a coating specialist determines remediation is required, then the coated components can only be returned to service if the following actions are performed: (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determined by adhesion testing endorsed by RG 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, (6) an evaluation is performed within 2 years and every 2 years until the coating is repaired, replaced, or removed. Revise Service Water Integrity Program procedures for inspecting the interior of coated components to include one or more of the following methods to determine the condition of the coating and the condition of the component under the degraded coating when conditions such as cracking, peeling, blisters, delamination, rust, or flaking are identified during the visual examination.	B.1.41	Prior to May 1, 2024	GNRO-2013/00096 GNRO-2014/00030 GNRO-2014/00076 GNRO-2015/00055

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS				
Item No.	**Commitment**	**FSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
35 (cont.)	1. Lightly tapping and scraping the coating to determine the coating integrity. 2. Wet-sponge testing or dry film testing to identify holidays in the coating. 3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area. 4. Ultrasonic testing to determine if the component's wall thickness meets the minimum thickness criteria. Revise Service Water Integrity Program documents to visually inspect 50 percent of coated internal surfaces of piping or a minimum of 73 locations of 360 degrees of linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations will be based on coating degradation susceptibility, operating experience, vendor recommendation, and safety significance. Inspect all accessible coated internal surfaces of tanks. Revise Service Water Integrity Program documents to include the following coating integrity acceptance criteria: (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to a few small intact blisters that are completely surrounded by sound coating bonded to the surface. Revise Service Water Integrity Program documents to include the following coating integrity corrective actions: In the event peeling, delamination, cracking, or loss of adhesion is identified, follow-up evaluations including adhesion testing endorsed by RG 1.54 will be performed. In the event the base metal is exposed and the visual inspection identifies corrosion, this inspection finding will be entered into the corrective action program, and an evaluation will confirm the component remains acceptable for continued service. As necessary, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component remains capable of performing its intended function. If repair or replacement of the coating is postponed, the evaluation will consider the minimum wall thickness requirements and the rate of corrosion and confirm the component remains acceptable for continued service until the next inspection or repair opportunity, which will be within 2 years.			

APPENDIX A: GRAND GULF LICENSE RENEWAL COMMITMENTS				
Item No.	Commitment	FSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
35 (cont.)	Revise Service Water Integrity Program documents to specify a review of at least the two previous coating inspection results prior to conducting a coating inspection. Revise Service Water Integrity Program procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, “Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants.” Revise Service Water Integrity Program procedures to ensure that a nuclear coatings specialist qualified in accordance with ASTM D7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist,” will evaluate inspection findings and prepare post-inspection reports. Revise Service Water Integrity Program documents to state that coating inspection reports will include lists of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection or repair opportunity, which will be within 2 years. Revise Service Water Integrity Program procedures to ensure degraded coating/lining will be evaluated for potential flow blockage downstream prior to returning a coated component to service. Any coating that is found degraded and returned to service prior to repair or replacement will be evaluated by a coating specialist qualified in accordance with ASTM International standards endorsed by RG 1.54. The evaluation considers the effect of the coating/lining failure on the component’s intended function, problems identified during prior inspections, repair methods used during prior repairs, and known service history of the original coating.			
36	Revise program documentation to specify that components subject to wall-thinning mechanisms other than FAC, which are replaced with alternate materials (e.g. replacing a carbon steel pipe with stainless steel) shall continue to be periodically monitored at a frequency commensurate with their post-replacement wear rate and operating time.	B.1.22	Prior to May 1, 2024	GNRO-2013/00096

APPENDIX B

CHRONOLOGY

This appendix lists chronologically the routine licensing correspondence between the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff) and Entergy Operations, Inc., (Entergy or the applicant). This appendix also lists other correspondence on the staff's review of the Grand Gulf Nuclear Station, Unit 1 (GGNS) license renewal application (LRA) (under Docket No. 50-416).

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Date	**ADAMS Accession No.**	**Subject**
October 28, 2011	ML11308A052	Letter from Entergy to NRC, Submitting Grand Gulf, Unit 1, License Renewal Application
October 28, 2011	ML11308A101	Grand Gulf, Unit 1, License Renewal Application
November 9, 2011	ML11293A013	Letter from NRC to Entergy, Receipt and Availability of the License Renewal Application for the Grand Gulf Nuclear Station, Unit 1
November 9, 2011	ML11293A014	Federal Register Notice, Notice of Receipt and Availability of the License Renewal Application for the Grand Gulf Nuclear Station, Unit 1
December 16, 2011	ML11335A340	Letter from NRC to Entergy, Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from Entergy Operations, Inc. for Renewal of the Operating License for Gulf Nuclear Station, Unit 1
December 16, 2011	ML11335A341	Federal Register Notice, Notice of Opportunity for Hearing Regarding Renewal of Facility Operating License No. NPF-29 for an Additional 20 year Period, Inc. Grand Gulf Nuclear Station, Unit 1 (Docket No. 50-416)
January 4, 2012	ML11350A053	Letter from NRC to Entergy, Plan for the Scoping and Screening Regulatory Audit Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application Review
January 6, 2012	ML11362A433	Meeting Notice, Forthcoming Meeting to Discuss the License Renewal Process and Environmental Scoping for Grand Gulf Nuclear Station, Unit 1, License Renewal Application
January 18, 2012	ML12009A105	Letter from NRC to Entergy, Plan for the Aging Management Program Regulatory Audit Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application Review
April 3, 2012	ML12067A235	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 4, 2012	ML12068A233	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 11, 2012	ML12080A191	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 12, 2012	ML12074A008	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	ADAMS Accession No.	Subject
April 16, 2012	ML12076A014	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 17, 2012	ML12076A009	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 18, 2012	ML12087A001	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 25, 2012	ML12094A009	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 26, 2012	ML12101A360	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
April 30, 2012	ML12104A219	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 1, 2012	ML12123A077	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 3, 2012	ML12109A213	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 3, 2012	ML12124A255	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 9, 2012	ML12115A276	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 9, 2012	ML12115A090	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 9, 2012	ML12130A417	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 9, 2012	ML12130A419	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 14, 2012	ML12117A383	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 14, 2012	ML12136A063	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 15, 2012	ML12118A539	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 15, 2012	ML12137A265	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	**ADAMS Accession No.**	**Subject**
May 18, 2012	ML12153A367	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 24, 2012	ML12123A704	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 24, 2012	ML12125A373	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 25, 2012	ML12150A174	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 25, 2012	ML12150A182	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 25, 2012	ML12150A180	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 29, 2012	ML12139A055	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
May 30, 2012	ML12152A098	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 5, 2012	ML12137A296	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 5, 2012	ML12158A142	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 6, 2012	ML12159A213	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 8, 2012	ML12137A290	Letter from NRC to Entergy, Aging Management Programs Audit Report Regarding The Grand Gulf Nuclear Station, Unit 1
June 11, 2012	ML12164A430	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 11, 2012	ML12164A432	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 15, 2012	ML12151A265	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 20, 2012	ML12165A387	Letter from NRC to Entergy, Scoping and Screening Methodology Audit Report Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 20, 2012	ML12151A368	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	**ADAMS Accession No.**	**Subject**
June 21, 2012	ML12174A026	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 22, 2012	ML12152A345	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 22, 2012	ML12152A393	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 22, 2012	ML12177A128	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 22, 2012	ML12177A130	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 27, 2012	ML12164A174	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 27, 2012	ML12164A726	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
June 27, 2012	ML12157A056	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 3, 2012	ML12187A119	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 12, 2012	ML12198A018	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 17, 2012	ML12179A137	Memoranda, Summary of Telephone Conference Call Held on March 19, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 17, 2012	ML12180A541	Memoranda, Summary of Telephone Conference Call Held on March 14, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 17, 2012	ML12188A706	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 19, 2012	ML12202A055	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 23, 2012	ML12188A516	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 23, 2012	ML12206A059	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	**ADAMS Accession No.**	**Subject**
July 23, 2012	ML12206A058	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 25, 2012	ML12208A039	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 25, 2012	ML12208A166	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 26, 2012	ML12208A359	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 27, 2012	ML12200A138	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 27, 2012	ML12201B476	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 31, 2012	ML12180A467	Memoranda, Summary of Telephone Conference Call Held on April 3, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
July 31, 2012	ML12191A187	Memoranda, Summary of Telephone Conference Call Held on April 13, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 1, 2012	ML12191A026	Memoranda, Summary of Telephone Conference Call Held on April 25, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 7, 2012	ML12208A267	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 13, 2012	ML12227A291	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 15, 2012	ML12201B504	Memoranda, Summary of Telephone Conference Call Held on May 23, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 15, 2012	ML12220A337	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 15, 2012	ML12229A582	Letter from Entergy to NRC, Grand Gulf, Unit 1, License Renewal Application 2012 Annual Update.
August 15, 2012	ML12229A579	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 15, 2012	ML12193A071	Memoranda, Summary of Telephone Conference Call Held on May 15, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	**ADAMS Accession No.**	**Subject**
August 15, 2012	ML12202A214	Memoranda, Summary of Telephone Conference Call Held on May 30, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 21, 2012	ML12230A310	Letter from NRC to Entergy, Correction to Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 21, 2012	ML12235A229	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 23, 2012	ML12240A229	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 28, 2012	ML12193A046	Memoranda, Summary of Telephone Conference Call Held on May 2, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 28, 2012	ML12201B545	Memoranda, Summary of Telephone Conference Call Held on June 5, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
August 28, 2012	ML12209A148	Memoranda, Summary of Telephone Conference Call Held on June 8, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 4, 2012	ML12249A300	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 5, 2012	ML12234A671	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 7, 2012	ML12230A247	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 7, 2012	ML12242A545	Revision of Schedule for the Conduct of a Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493)
September 10, 2012	ML12214A572	Memoranda, Summary of Telephone Conference Call Held on July 11, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 12, 2012	ML12235A304	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 13, 2012	ML12257A353	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 14, 2012	ML12248A158	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	**ADAMS Accession No.**	**Subject**
September 14, 2012	ML12214A548	Memoranda, Summary of Telephone Conference Call Held on July 18, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 14, 2012	ML12237A295	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
September 24, 2012	ML12268A365	Inspection Report, Grand Gulf Nuclear Station, Unit 1, License Renewal Inspection
October 2, 2012	ML12277A188	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 2, 2012	ML12277A079	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 3, 2012	ML12270A249	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 9, 2012	ML12284A032	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 15, 2012	ML12290A108	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 15, 2012	ML12290A110	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 17, 2012	ML12278A036	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 19, 2012	ML12286A024	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 22, 2012	ML12297A204	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 31, 2012	ML12250A105	Memoranda, Summary of Telephone Conference Call Held on August 15, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
October 31, 2012	ML12264A387	Memoranda, Summary of Telephone Conference Call Held on August 21, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 5, 2012	ML12296A194	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 9, 2012	ML12271A252	Memoranda, Summary of Telephone Conference Call Held on August 22, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application

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Date	ADAMS Accession No.	Subject
November 9, 2012	ML12264A392	Memoranda, Summary of Telephone Conference Call Held on September 4, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 15, 2012	ML123210175	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 15, 2012	ML12264A649	Memoranda, Summary of Telephone Conference Call Held on August 29, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 19, 2012	ML12325A173	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 20, 2012	ML12312A453	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 29, 2012	ML12339A011	Letter from Entergy to NRC, Response to Requests for Additional Information Regarding the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
November 30, 2012	ML12333A218	Letter from NRC to Entergy, Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
December 18, 2012	ML12354A467	Grand Gulf Nuclear Station, Unit 1, Response to Requests for Additional Information (RAI) Set 42, dated November 20, 2012.
December 18, 2012	ML12354A465	Grand Gulf Nuclear Station, Unit 1, Response to Requests for Additional Information (RAI) Set 43, dated November 30, 2012.
January 3, 2013	ML12271A471	Memoranda, Summary of Telephone Conference Call Held on September 7, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
January 3, 2013	ML12334A347	Memoranda, Summary of Telephone Conference Call Held on September 28, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
January 3, 2013	ML12334A586	Memoranda, Summary of Telephone Conference Call Held on October 9, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
January 11, 2013	ML12335A172	Memoranda, Summary of Telephone Conference Call Held on October 15, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
January 14, 2013	ML12338A650	Memoranda, Summary of Telephone Conference Call Held on October 26, 2012, Between NRC and Entergy, Concerning RAIs Pertaining to the Grand Gulf Nuclear Station, Unit 1, License Renewal Application
January 18, 2013	ML13022A474	Grand Gulf Nuclear Station, Unit 1 - Response to Requests for Additional Information (RAI) 4.2.1-2b and 4.7.3-1a
January 31, 2013	ML13016A044	Grand Gulf SER with Open Items Transmittal Letter
January 31, 2013	ML13032A194	Safety Evaluation Report With Open Items Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1

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Date	**ADAMS Accession No.**	**Subject**
February 26, 2013	ML13002A430	Revision of Schedule for the Conduct of a Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7385)
March 12, 2013	ML13058A120	Request for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493) – Set 47
March 12, 2013	ML13045A917	RAI for the Review of the Grand Gulf Nuclear Station License Renewal Application (TAC No. ME7493)
April 2, 2013	ML13093A328	Comments on Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, dated January 31, 2013
April 3, 2013	ML13064A058	Summary of Telephone Conference Call Held on February 19, 2013, Between the NRC and Entergy Operations, Inc., Concerning Requests for Additional Information Pertaining to the Grand Gulf Nuclear Station, License Renewal Application (TAC. No. ME7493)
August 8, 2013	ML13221A272	Follow-up Actions from Teleconference Held on August 1, 2013, Related to Pre-Decisional Enforcement Conference Between the NRC and Grand Gulf on Tuesday July 16, 2013
April 15, 2013	ML13107A015	Grand Gulf Nuclear Station, Unit 1 - Response to Requests for Additional Information (RAI) Set 44, dated March 12, 2013
May 23, 2013	ML13120A176	Revision of Schedule for the Conduct of Review of the Grand Gulf Nuclear Station, License Renewal Application and Project Manager Change (TAC No. ME7493)
August 28, 2013	ML13227A394	Request for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493) – Set 47
September 12, 2013	ML13238A234	Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493) – Set 49
September 23, 2013	ML13266A368	Grand Gulf Nuclear Station, Unit 1 - Response to Requests for Additional Information (RAI) Set 47, dated August 28,2013
October 17, 2013	ML13291A126	Entergy, Reply to Notice of Violation; EA-13-058
October 25, 2013	ML13302A598	Grand Gulf Nuclear Station, Unit 1, License Renewal Application 2013 Annual Update
November 21, 2013	ML13263A225	Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493) – Set 48
December 20, 2013	ML13358A041	Grand Gulf Nuclear Station, Unit 1 - Response to Request for Additional Information (RAI) Set 48 dated November 21, 2013
January 2, 2014	ML13318A805	Request for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493) – Set 50
April 15, 2014	ML14050A079	Regarding the Response to Request for Additional Information, Set 47, for the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493)
May 13, 2014	ML14133A364	Grand Gulf Nuclear Station, Unit 1 - Response to Request for Additional Information (RAI) dated January 2, 2014
July 10, 2014	ML14184B183	Summary of Telephone Conference Call Held on June 18, 2014, Between the NRC and Entergy Operations, Inc., Concerning Draft RAI 3.0.5-1E (Operating Experience Follow-Up) for the Grand Gulf, Unit 1, License Renewal Application (TAC No. ME7493)

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Date	**ADAMS Accession No.**	**Subject**
September 11, 2014	ML14238A620	Request for Additional Information for the Review of the Grand Gulf Nuclear Station License Renewal Application, Set 51 (TAC No. ME7493)
October 27, 2014	ML14301A102	Letter from Entergy to NRC, Grand Gulf, Unit 1, License Renewal Application 2014 Annual Update.
November 6, 2014	ML14311A694	Grand Gulf Nuclear Station, Unit 1- Response to Request for Additional Information (RAI) Set 51 dated September 11, 2014
February 19, 2015	ML14258A145	August 21, 2014, Summary of Telephone Conference Call Held Between the NRC and Entergy Operations, Inc., Concerning RAI Set 51 For The Grand Gulf, Unit 1, License Renewal Application (TAC No. ME7493)
March 30, 2015	ML15089A524	Grand Gulf Nuclear Station, Unit 1 - Follow-up response to NRC Letter, “Updated Fluence Methodology License Amendment Request Unacceptable With Opportunity To Supplement,” dated February 18, 2015, to provide Independent Benchmarking of the 3D Fluence Calculation Method as documented in Letter GNRO-2015/00011, also dated February 18, 2015
April 6, 2015	ML15085A493	Request for Additional Information for the Review of the Grand Gulf Nuclear Stations License Renewal Application, Set 52 (TAC No. 7493)
April 20, 2015	ML15092A250	March 19. 2015, Record of Conference Call for GGNS License Renewal – RAI Set 52.
April 22, 2015	ML15107A079	Project Manager Change for the License Renewal of Grand Gulf Nuclear Station, Unit 1 (TAC No. ME7493)
May 20, 2015	ML15141A178	Grand Gulf Nuclear Station, Unit 1 - Response to Request for Additional Information (RAI) Set 52, dated April 6, 2015
July 29, 2015	ML15212A747	Grand Gulf Nuclear Station, Unit 1 - Response to License Renewal Amendment Request for Additional Information Set 47, Question 4.2.1-2c (5) (b)
August 19, 2015	ML15231A307	Grand Gulf Nuclear Station, Unit 1 - Responses to Request for Additional Information (RAI) Set 52, RAIs 3.0.31-FWS-2a and 3.0.3-2b, dated June 18, 2015
September 1, 2015	ML15245A295	Grand Gulf Nuclear Station, Unit 1 - Response to License Renewal Application (LRA) Request for Additional Information (RAI) Set 47, Question 4.2.1-2c (5) (a) i
October 14, 2015	ML15215A041	Summary of Telephone Conference Call held on June 18, 2015, between the NRC and Entergy Operations, Inc., Concerning Request for Additional Information Responses, Pertaining to the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493)
October 28, 2015	ML15286A108	Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493)-Set 53
November 23, 2015	ML15327A181	Responses to Request for Additional Information (RAI) Set 53, dated October 28, 2015
December 10, 2015	ML15344A283	Letter from Entergy to NRC, Grand Gulf, Unit 1, License Renewal Application 2015 Annual Update.
December 14, 2015	ML15348A402	Amended Response to Request for Additional Information (RAI) 4.2.3-2, dated October 28, 2015, Grand Gulf Nuclear Station, Unit 1
January 12, 2016	ML15355A034	December 28, 2015, Summary of Teleconference for GGNS Set 53 RAI Responses.

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Date	**ADAMS Accession No.**	**Subject**
February 3, 2016	ML16012A391	Schedule Revision For the Review of the Grand Gulf Nuclear Station, License Renewal Application (TAC No. ME7493)
February 26, 2016	ML16057A670	Grand Gulf, Unit 1 - Supplemental Correction Response to License Renewal Amendment Request for Additional Information Set 47.
March 31, 2016	ML16067A240	Advisory Committee on Reactor Safeguards Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application - Transmittal of Final Safety Evaluation Report.
April 4, 2016	ML16064A183	Final Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1
April 4, 2016	ML16095A118	GNRO-2016/00018 - Grand Gulf Nuclear Station License Renewal Documents to Support Review of Application for Renewal of license: Report Number MPM-814779, Revision 3, Neutron Transport Analysis for Grand Gulf Nuclear Station and Engineering Report GGNS-NE-15-00003.
June 6, 2016	ML16158A487	Grand Gulf, Unit 1 - Comments Regarding License Renewal Safety Evaluation Report ML16090A252 Dated April 4, 2016.
July 28, 2016	ML16210A526	Regional Administrator's Letter to William Dean Regarding the Grand Gulf Nuclear Station License Renewal Application.
September 23, 2016	ML16267A400	Clarification of Grand Gulf Nuclear Station Containment Leak Rate Program Description Grand Gulf Nuclear Station, Unit 1 Docket No. 50-416
October 3, 2016	ML16277A573	Additional Clarification of the Grand Gulf Nuclear Station Containment Leak Rate Program Description Grand Gulf Nuclear Station, Unit 1 Docket No. 50-416
October 3, 2016	ML16279A517	Advisory Committee on Reactor Safeguards Review of the Grand Gulf Nuclear Station, Unit 1, License Renewal Application – Transmittal Of Updated Containment Leak Rate Aging Management Program Review (TAC No. ME7493)
October 12, 2016	ML16280A285	Summary of Teleconference Held on September 21, 2016, Between the NRC and Entergy Co., concerning Containment Leak Rate Program pertaining to the Grand Gulf Nuclear Station Unit 1 (TAC Nos. ME7493)
October 19, 2016	ML16280A506	Summary of Teleconference Held on September 28, 2016, Between the NRC and Entergy Co., concerning Containment Leak Rate Program pertaining to the Grand Gulf Nuclear Station Unit 1 (TAC Nos. ME7493)

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 Grand Gulf Nuclear Station, Unit 1 (GGNS).

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– – – RG 1.45, “Guidance on Monitoring and Responding to Reactor Coolant System Leakage.”
– – – RG 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.”
– – – RG 1.65, “Materials and Inspections for Reactor Vessel Closure Studs.”
– – – RG 1.75, “Physical Independence of Electric Systems.”
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NRC FORM 335 (12-2010) NRCMD 3.7 U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.) NUREG-2211
2. TITLE AND SUBTITLE Supplemental Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1	3. DATE REPORT PUBLISHED MONTH: November YEAR: 2016 4. FIN OR GRANT NUMBER
5. AUTHOR(S) See Appendix C.	6. TYPE OF REPORT Technical 7 PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION NAME AND ADDRESS (If NRC, provide Division, Office or Region, U. S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)
Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

9. SPONSORING ORGANIZATION NAME AND ADDRESS (If NRC, type "Same as above" if contractor, provide NRC Division, Office or Region, U. S. Nuclear Regulatory Commission, and mailing address.)
Same as above

10. SUPPLEMENTARY NOTES
Docket Nos. 50-416

11. ABSTRACT (200 words or less)
This final safety evaluation report (SER) documents the technical review of the Grand Gulf Nuclear Station, Unit 1 (GGNS), license renewal application (LRA) by the United States Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated October 28, 2011, Entergy Operations Inc. (Entergy) 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. GGNS requests renewal of the GGNS operating licenses (Operating Licenses Nos. NPF-29) for a period of 20 years beyond the current expiration at midnight November 1, 2024, for Unit 1. This final SER documents the staff's review and findings related to license renewal.

GGNS is located approximately 20 miles southwest of Vicksburg, Mississippi. The NRC issued the operating licenses for GGNS on November 1, 1984, for Unit 1. GGNS is a boiling water reactor design. General Electric supplied the nuclear steam supply system and Allis Chalmers Power Systems furnished the turbine generator set. The containment is a steel lined reinforced concrete structure designed by Bechtel Power Corporation. The GGNS licensed power output is 4,408 megawatt thermal.

This final SER presents the status of the staff's review of information through October 3, 2016, the cutoff off date for consideration in the final SER.

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)	13 AVAILABILITY STATEMENT: unlimited
10 CFR Part 54 License Renewal Grand Gulf Nuclear Station, Unit 1 Entergy Operating Inc. Aging Management Time-Limited Aging Management Scoping and Screening NPF-29 Docket No. 50-416.	14 SECURITY CLASSIFICATION *(This Page)* unclassified *(This Report)* unclassified 15. NUMBER OF PAGES 16. PRICE

NRC FORM 335 (12-2010)

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NUREG-2211

Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1

November 2016