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NUREG-2101

Safety Evaluation Report

Related to the License Renewal of Salem Nuclear Generating Station

Docket Numbers 50-272 and 50-311

PSEG Nuclear, LLC

Office of Nuclear Reactor Regulation

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Salem Nuclear Generating Station, Units 1 and 2, (Salem) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated August 18, 2009, PSEG Nuclear, LLC (PSEG or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the *Code of Federal Regulations*, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.” PSEG requests renewal of the operating licenses (Facility Operating License Numbers DPR-70 and DPR-75) for a period of 20 years beyond the current expiration at midnight August 13, 2016, for Unit 1, and at midnight on April 18, 2020, for Unit 2.

Salem is located approximately 40 miles from Philadelphia, PA, and 8 miles from Salem, NJ. The NRC issued the construction permits for Unit 1 and Unit 2 on August 25, 1968. The NRC issued the operating license for Unit 1 on December 1, 1976, and for Unit 2 on May 20, 1981. Both units are pressurized water reactors that were designed and supplied by Westinghouse. License Amendment Nos. 243 (Salem Unit 1) and 224 (Salem Unit 2), dated May 25, 2001, authorized a 1.4 percent increase in the licensed rated power level of each unit to 3,459 megawatt thermal (MWt).

This SER presents the status of the staff’s review of information submitted through May 18, 2011, the cutoff date for consideration in this SER. The staff has resolved all issues associated with requests for additional information and closed all open items since publishing the SER with Open Items. The staff did not identify any new open items that must be resolved before any final determination can be made on the LRA.

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ABBREVIATIONS

AC	alternating current
ACAR	aluminum-alloyed reinforced
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agencywide Document Access and Management System
AERM	aging effect requiring management
AFW	auxiliary feedwater
AMP	aging management program
AMR	aging management review
AMSAC	ATWS Mitigation System Actuation Circuitry
ANSI	American National Standards Institute
ARC	alternate repair criteria
ART	adjusted reference temperature
ASA/USAS	American Standards Association/United States of America Standards
ASME	American Society of Mechanical Engineers
ASN	analysis section number
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AWWA	American Water Works Association
B&PV	Boiler and Pressure Vessel
BIT	boron injection tank
BMI	bottom-mounted instrument
BMV	bare metal visual
BTP	branch technical position
BWR	boiling-water reactor

CASS	cast austenitic stainless steel
CDM	component data module
CEA	control element assembly
CFR	*Code of Federal Regulations*
CH	cranes & hoists
CISI	containment inservice inspection
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CO_2	carbon dioxide
CRD	control rod drive
Cu	copper
CUF	cumulative usage factor
CVCS	chemical and volume control system
DBA	design-basis accident
DBE	design-basis event
DO	dissolved oxygen
DW	demineralized water
EAF	environmentally-assisted fatigue
ECCS	emergency core cooling system
ECT	eddy current testing
EDG	emergency diesel generator
EFPY	effective full-power year
EN	shelter or protection
EPRI	Electric Power Research Institute
EQ	environmental qualification
ESF	engineered safety features
F_{en}	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission

FR	*Federal Register*
ft-lb	foot-pound
GALL	Generic Aging Lessons Learned Report
GEIS	Generic Environmental Impact Statement
GL	generic letter
gpd	gallons per day
gpm	gallons per minute
HELB	high-energy line break
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
HWHS	heating water and heating steam
HX	heat exchanger
I&C	instrumentation and controls
IASCC	irradiation-assisted stress-corrosion cracking
ID	inside diameter
IGSCC	intergranular stress-corrosion cracking
ILRT	integrated leak rate testing
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
ISG	interim staff guidance
ISI	inservice inspection
K_e	elastic-plastic strain correction factor
ksi	thousands of pounds per square inch
KV or kV	kilovolt
LBB	leak-before-break

LBLOCA	large-break loss-of-coolant accident
LOCA	loss-of-coolant accident
LRA	license renewal application
MCAR	main condenser and air removal
MCFW	main condensate and feedwater
MELB	moderate-energy line break
MIC	microbiologically-influenced corrosion
mph	miles per hour
MRP	modification/rework package Materials Reliability Program
MS	main steam
MSIP	mechanical stress improvement procedures Mechanical Stress Improvement Process
MSIV	main steam isolation valve
MTA	main turbine and auxiliaries
MWe	megawatts-electric
MWt	megawatts-thermal
n/cm^2	neutrons per square centimeter
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NJPDES	New Jersey Pollutant Discharge Elimination System
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	nuclear steam supply system
OBE	operating basis earthquake
ODSCC	outside-diameter stress-corrosion cracking

OI	open item
OTSG	once-through steam generator
PASS	post-accident sampling system
pH	potential of hydrogen
PORV	pilot-operated relief valve
ppm	parts per million
PSEG	PSEG Nuclear, LLC
psi	pounds per square inch
P-T	pressure-temperature
PT	penetrant testing
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized water reactor
PWSCC	primary water stress-corrosion cracking
PWST	primary water storage tank
QA	quality assurance
QAP	quality assurance program
RAI	request for additional information
RCCA	rod cluster control assembly
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RI-ISI	risk informed-inservice inspection
RIS	regulatory issue summary
RM	radiation monitoring
RPV	reactor pressure vessel

RT_{NDT}	reference temperature nil-ductility transition
RT_{PTS}	reference temperature for pressurized thermal shock
RV	reactor vessel
RVID	Reactor Vessel Integrity Database
RWST	refueling water storage tank
Salem	Salem Nuclear Generating Station
SAP	Systems, Applications, and Products in Data Processing
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SE	safety evaluation
SEN	significant event notification
SER	safety evaluation report
SFC	spent fuel cooling
SFP	spent fuel pool
SG	steam generator
SGBD	steam generator blowdown
SGMP	Steam Generator Management Program
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SSC	system, structure, and component
SW	service water
TAN	total acid number
TLAA	time-limited aging analysis
TS	technical specification(s)
UFSAR	updated final safety analysis report
USE	upper-shelf energy
UT	ultrasonic testing

V	volt
VCT	volume control tank
VT	visual testing
WCAP	Westinghouse Commercial Atomic Power Vendor Report
WOG	Westinghouse Owners' Group
Zn	zinc
¼T	one-fourth of the way through the vessel wall measured from the internal surface of the vessel

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Salem Nuclear Generating Station, Units 1 and 2, (Salem) as filed by PSEG Nuclear, LLC (PSEG or the applicant). By letter dated August 18, 2009, PSEG submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the Salem operating licenses 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 Samuel Cuadrado de Jesús. Mr. Cuadrado de Jesús may be contacted by telephone at 301-415-2946 or by electronic mail at Samuel.CuadradoDeJesus@nrc.gov. Alternatively, written correspondence may be sent to the following address:

Division of License Renewal
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Attention: Samuel Cuadrado de Jesús, Mail Stop O11-F1

In its August 18, 2009, submission letter, the applicant requested renewal of the operating licenses issued under Section 103 (Operating License Nos. DPR-70 and DPR-75) of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current expiration at midnight August 13, 2016, for Unit 1, and at midnight April 18, 2020, for Unit 2. Salem is located approximately 40 miles from Philadelphia, PA, and 8 miles from Salem, NJ. The NRC issued the construction permits for Unit 1 and Unit 2 on September 25, 1968. The NRC issued the operating license for Unit 1 on December 1, 1976, and for Unit 2 on May 20, 1981. Both units are pressurized water reactors (PWRs) that were designed and supplied by Westinghouse. The licensed power output of both units is 3,459 megawatt thermal. The updated final safety analysis report (UFSAR) shows details of the plants and the site.

The license renewal process consists of two concurrent reviews, a technical review of safety issues and an environmental review. The NRC regulations in 10 CFR Part 54 and 10 CFR Part 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions,” respectively, set forth requirements for these reviews. The safety review for the Salem license renewal is based on the applicant’s LRA and on its 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 May 18, 2011. 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 Salem Free Library, 112 West Broadway, Salem, NJ 08079. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC Web site at http://www.nrc.gov.

This SER summarizes the results of the staff's safety review of the LRA and describes the technical details that were considered in evaluating the safety aspects of the units' 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 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated September 2005.

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 found in 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 also prepared a draft plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." Issued separately from this SER, this supplement discusses the environmental considerations for the license renewal of Salem along with those of Hope Creek Generating Station. The staff issued the draft Supplement 45 to NUREG-1437 in October 2010. After considering comments on this draft, the staff will publish the final, plant-specific GEIS Supplement 45 in March 30, 2011.

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 on the basis of economic and antitrust considerations, rather than on technical limitations; however, some individual plant and equipment designs may have been engineered based on 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. Published on May 8, 1995, in Volume 60, page 22461, of the *Federal Register* (60 FR 22461), the 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 (IPA) process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

Concurrent with these initiatives, the staff pursued a separate rulemaking effort (Volume 61, page 28467, of the *Federal Register* (61 FR 28467), dated 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 (NEPA).

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 exception of the detrimental aging effects on the function 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 defines the scope of license renewal as including SSCs: (1) that are safety-related, (2) whose failure could affect safety-related functions, or (3) that are relied on to demonstrate compliance with NRC regulations for fire protection, environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), a license renewal applicant must review all SSCs within the scope of 10 CFR Part 54 to identify SCs subject to an aging management review (AMR). Those SCs subject to an AMR are those which perform an intended function without moving parts or without a change in configuration or properties (i.e., are "passive"), and are not subject to replacement based on a qualified life or specified time period (i.e., are "long-lived"). As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that aging effects will be managed in such a way that the intended function(s) of those SSCs will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation; however, active equipment is considered adequately monitored and maintained by existing programs. In other words, detrimental aging effects that may affect active equipment are readily detectable and can be 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), each LRA is required to include a UFSAR supplement that must have a summary description of the applicant's programs and activities for managing aging effects and the 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 are made about the length of time the plant can operate. These assumptions are incorporated into design calculations for several plant SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must 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 effects of aging on these SSCs can be adequately managed for the period of extended operation.

In 2005, the staff 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" (NEI 95-10), issued in June 2005 by the NEI. NEI 95-10 details an acceptable method of implementing the Rule. The staff also used the SRP-LR to review this application.

In its LRA, the applicant stated that it used the process defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," issued in July 2001 and subsequently revised in September 2005. The GALL Report provides a summary of staff-approved aging management programs (AMPs) for the aging of many SCs subject to an AMR. An applicant's willingness to commit to implementing these staff-approved AMPs could potentially reduce the time, effort, and resources in reviewing an applicant's LRA, and thereby, improve 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 SCs used throughout the industry. The report is also a reference for both applicants and staff reviewers to quickly identify AMPs and activities that can provide adequate aging management during the period of extended operation.

1.2.2 Environmental Review

Part 51 of 10 CFR contains the environmental protection regulations. 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 the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings applicable to all nuclear power plants. These generic findings are codified in Appendix B to Subpart A of 10 CFR Part 51. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, which included any new and significant information that the GEIS might not have considered. As part of its scoping process, the staff held two public meetings on November 5, 2009, at the Salem County Emergency Services Building in Woodstown, NJ, to identify plant-specific environmental issues that might impact Hope Creek Generating Station (HCGS) or Salem Nuclear Generating Station, Units 1 and 2. The draft plant-specific GEIS Supplement 45, issued in October 2010, documents the results of the environmental review and includes a preliminary recommendation that the Commission determine that the adverse environmental impacts of license renewal for Salem and HCGS are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable. Two public meetings were held on November 17, 2010, in Woodstown, NJ, to discuss the draft plant-specific GEIS Supplement 45. After considering comments on the draft, the staff prepared and published on March 30, 2011 a final plant-specific GEIS supplement separately from this report.

1.3 Principal Review Matters

Part 54 of 10 CFR describes the requirements for renewing operating licenses for nuclear power plants. The staff performed its technical review of the LRA in accordance with NRC guidance and 10 CFR Part 54 requirements. Section 54.29 of 10 CFR sets forth the standards for renewing a license. This SER describes the results of the staff's safety review.

In accordance with 10 CFR 54.19(a), the NRC requires a license renewal applicant to submit general information. The applicant provided this general information in LRA Section 1, which it submitted by letter dated August 18, 2009. The staff reviewed LRA Section 1 and found that the applicant had submitted the information required by 10 CFR 54.19(a).

In accordance with 10 CFR 54.19(b), the staff requires that each 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." The applicant stated the following in LRA Section 1.1.10 on this issue:

> 10 CFR 54.19(b) requires that "each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The current indemnity agreements (No.P08-046 for Salem Unit 1 and No.X08-084 for Salem Unit 2) state in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire; provided that, except as may otherwise be provided in applicable regulations or orders of the Commission, the term of this agreement shall not terminate until all the radioactive material has been removed from the location and transportation of the radioactive material from the location has ended as defined in subparagraph 5(b), Article I. Item 3 of the Attachment to the indemnity agreement includes license numbers, DPR-70 and DPR-75. Applicant requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the terms of the current licenses and the terms of the renewed licenses. Applicant understands that no changes may be necessary for this purpose if the current license numbers are retained.

The staff intends to maintain the original license number upon issuance of the renewed license, if approved. Therefore, conforming changes to the indemnity agreement need not be made and the 10 CFR 54.19(b) requirements have been met. In accordance with 10 CFR 54.21, the staff requires that each LRA contain:

(a) an IPA
(b) a description of any CLB changes during the staff's review of the LRA
(c) an evaluation of TLAAs
(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).

In accordance with 10 CFR 54.21(b), the staff 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 of the facility that materially affect the contents of the LRA, including the UFSAR supplement. The applicant fulfilled this requirement by a letter dated August 3, 2010 (Agencywide Document Access and Management System (ADAMS) Accession No. ML102180171).

In accordance with 10 CFR 54.22, the staff requires that an applicant's LRA include changes or additions to the technical specifications necessary to manage aging effects during the period of extended operation. In LRA Section 1, the applicant stated the following:

> There were no Technical Specification Changes identified necessary to manage the effects of aging during the period of extended operation.

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

As required by 10 CFR 54.25, the ACRS will issue a report to document its evaluation of the staff's LRA review and associated SER. SER Section 5 will incorporate the ACRS report once it is issued. SER Section 6 will document the findings required by 10 CFR 54.29.

1.4 <u>Interim Staff Guidance</u>

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 NRC's safety goal of ensuring adequate protection of public health and safety and the environment. 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 ISG, as well as the SER section in which it is addressed.

Table 1.4-1 Current Interim Staff Guidance

ISG Issue (Approved ISG No.)	Purpose	SER Section
LR-ISG-2007-02	Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.2.17

1.5 Summary of the Open Items

As a result of its review of the LRA, including additional information submitted through February 25, 2011, the staff closed the four open items (OIs) previously identified in the "Safety Evaluation Report with Open Items Related to the License Renewal of Salem Nuclear Generating Station" (ADAMS Accession No. ML103120172). Since the issuance of the SER with Open Items, the staff identified new issues based on industry-wide operating experience and issued new RAIs to all current applicants that had not previously addressed these issues. In response to these RAIs, the applicant has provided additional clarification on its sampling plans for the One-Time Inspection (SER Section 3.0.3.1.11) and Selective Leaching of Materials (SER Section 3.0.3.1.12) programs. As a result of the applicant's responses, the staff was able to close all of the open items as well as resolve the new RAIs.

OI 3.0.3.2.15-1. (SER Section 3.0.3.2.15 – Structures Monitoring Program)

The LRA states that the spent fuel pools (SFPs) have experienced leakage of borated water during refueling outages, and in-leakage of contaminated water was noted during the field walkdown. The applicant reported that leakage into the telltale drains on the west side of the SFP is occurring at a rate of about 100 gallons per day (gpd), and a small amount of leakage, approximately one-eighth of a gallon per day, is migrating through the inaccessible east wall of the pool. The applicant further stated that no evidence of through-wall leakage has been observed on the accessible west wall since the telltale drains were cleared in 2003. The staff is concerned that this leakage of borated water may result in degradation of either the concrete or embedded steel reinforcement of the SFP.

In response to the staff's requests, the applicant committed to: (1) take concrete core samples from both the east and west walls, which will expose the rebar for investigation; (2) visually inspect the accessible west wall every 18 months; and (3) monitor the leakage to confirm that the leakage amount and chemistry is not changing during the period of extended operation. The staff has made the concrete core samples a license condition for the renewed license. The results of the samples must be reported to the NRC. If degradation is detected, the condition will be entered into the corrective action program and addressed. No leakage from the west wall has been observed since 2003; the staff believes evidence of no degradation from a core sample in 2015 would provide reasonable assurance that degradation will not occur during the period of extended operation. Open Item OI 3.0.3.2.15-1 is closed.

<u>OI 3.0.3.2.10-1</u>. (SER Sections 3.0.3.2.10 and 3.0.3.3.4 – Buried Piping Inspection and Buried Non-Steel Piping Inspection Programs)

Because of recent events involving leakage from buried or underground piping, the staff requested additional information to evaluate how the applicant considered industry and plant-specific operating experience in its buried piping programs. In response to these concerns, the applicant has completed or committed to complete an extensive number of inspections in the 10-year period prior to the period of extended operation, including an inspection of 225 feet of the auxiliary feedwater system piping and 235 feet of the safety related portions of the compressed air system piping. The applicant will conduct six inspections of the piping in the fire protection, service water, auxiliary feedwater, and compressed air systems during each of the 10-year periods of extended operation. The applicant also committed to perform a soil characterization study and will double the number of inspections if the soil is determined to be corrosive. The staff finds that the applicant's coatings of piping and backfill requirements are acceptable. Salem's buried piping does not contain hazardous materials (as defined in the GALL Report, NUREG-1801, Revision 2). The staff finds Salem's buried piping programs acceptable to manage the aging of its buried piping. Open Item OI 3.0.3.2.10-1 is closed. See SER Sections 3.0.3.2.10 and 3.0.3.3.4 for additional details.

<u>OI 3.1.2.2.16-1</u>. (SER Section 3.1.2.2.16-1 – Cracking Due to Stress-Corrosion Cracking and Primary Water Stress-Corrosion Cracking (Tube-To-Tubesheet Welds))

The SRP-LR and GALL Report state that primary water stress-corrosion cracking (PWSCC) could occur on the primary coolant side of the PWR steel steam generator (SG) tube-to-tubesheet welds made or clad with nickel alloy; this aging effect is only addressed for once-through SGs (OTSGs)—not for recirculating SGs. Given that American Society of Mechanical Engineers (ASME) Code Section XI does not require any inspection of the tube-to-tubesheet welds, nor does any specific NRC order or bulletin, the staff's concern is that, for Alloy 600 tubesheet cladding, the autogenous tube-to-tubesheet weld may not have sufficient chromium content to prevent the initiation of PWSCC that could propagate into/through the weld, causing a failure of the weld and reactor coolant pressure boundary for both recirculating and OTSGs. Therefore, unless the NRC has approved a redefinition of the pressure boundary in which the autogenous tube-to-tubesheet weld is no longer included, or the tubesheet cladding and welds are not susceptible to PWSCC, the staff considers that the effectiveness of the primary water chemistry program should be verified to ensure that PWSCC cracking does not occur.

By letter dated November 4, 2010, the staff issued RAI 3.1.1-03 requesting that the applicant provide a plant-specific AMP that will complement the primary water chemistry program in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds, or provide a rationale for why such a program is not needed. In response to the staff's RAI, the applicant committed in Commitment No. 51 to develop a plan for each unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds. Each plan will consist of two options that are discussed and documented in SER Section 3.1.2.2.16-1. The staff finds the plans for Units 1 and 2 acceptable because the applicant will manage the aging effect of cracking due to PWSCC in the SG tube-to-tubesheet welds either by demonstrating that those welds are no longer required or by implementing a one-time inspection to determine if PWSCC is present. Open item OI 3.1.2.2.16-1 is closed.

OI 4.3.4.2-1. (SER Sections 3.0.3.2.18, 4.3.4.2, and 4.3.7.2 – Metal Fatigue of Components and Piping)

During its review of the AP1000 design certification, the staff identified concerns regarding results of the WESTEMS™ program used by the applicant for ASME Code fatigue analyses. The AP1000 Westinghouse's responses to NRC questions regarding the AP1000 Technical Report describe the ability of users to modify intermediate data used in the analyses and different approaches for summation of moment stress terms. These items may impact the calculated fatigue cumulative usage factor (CUF). As a result of these concerns, the staff issued an RAI to the applicant asking whether the issues identified in the AP1000 review were applicable to the use of WESTEMS™ at Salem and to describe how the applicant uses WESTEMS™. In addition, the staff requested a benchmarking evaluation for two of the locations, monitored by WESTEMS™, and a comparison to the traditional ASME Code Section III CUF calculations. The staff reviewed the applicant's response and conducted an audit on January 18 and 19, and February 8, 2011, to review the applicant's benchmarking calculations. The audit confirmed that for the two monitored locations, Salem's use of WESTEMS™ NB-3200 module produced results that were consistent with those using the methodology in ASME Code Section III, NB-3200. By letter dated February 24, 2011, the applicant also provided Commitment Nos. 53 and 54 that address the issues that were identified in the AP1000 review. The staff's concern with Salem's use of the WESTEMS™ NB-3200 module is resolved.

In addition, the staff also noted that, while the applicant selected locations per NUREG/CR-6260 to evaluate the impact of the reactor coolant environment, it is not clear whether there were more limiting plant-specific locations that should be considered. Specifically, the staff was concerned whether the applicant has verified that the locations listed in NUREG/CR-6260 are bounding for Salem as compared to other plant-specific locations that are also subject to the effects of the reactor coolant environment on fatigue usage. In its letter dated December 21, 2010, the applicant committed in Commitment No. 52 to perform a review of design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260-based locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for Salem. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. The staff reviewed and accepted Commitment No. 52 as it is consistent with the recommendations in SRP-LR Sections 4.3.4.2 and 4.3.2.2, and GALL AMP X.M1. Additional information is documented in SER Sections 3.0.3.2.18, 4.3.4.2, and 4.3.7. Open Item OI 4.3.4.2-1 is closed.

1.6 Summary of Confirmatory Items

There are no confirmatory items associated with this SER.

1.7 Summary of Proposed License Conditions

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

The first license condition requires the applicant to update the UFSAR supplement required by 10 CFR 54.21(d) in the UFSAR following the issuance of the renewed license.

The second license condition requires the applicant to complete the commitments in the UFSAR supplement and notify the NRC in writing when implementation of those activities required prior to the period of extended operation are complete and can be verified by NRC inspection.

The third license condition requires that all capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC.

The fourth license condition requires the applicant to take one core sample in the Unit 1 SFP west wall, by the end of 2013, and one core sample in the east wall where there have been indications of borated water ingress through the concrete, by the end of 2015. The core samples (east and west walls) will expose the rebar, which will be examined for signs of corrosion. Any sample showing signs of concrete degradation and/or rebar corrosion will be entered into the licensee's corrective action program for further evaluation. The licensee shall submit a report in accordance with 10 CFR 50.4 no later than three months after each sample is taken on the results, recommendations, and any additional planned actions.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 <u>Scoping and Screening Methodology</u>

2.1.1 Introduction

Title 10 of the *Code of Federal Regulations,* Section 54.21 (10 CFR 54.21), “Contents of Application–Technical Information,” requires for each license renewal application (LRA) an integrated plant assessment (IPA). The IPA must list and identify all of the systems, structures, and components (SSCs) within the scope of license renewal and all structures and components (SCs) subject to an aging management review (AMR), in accordance with 10 CFR 54.4.

LRA Section 2.1, “Scoping and Screening Methodology,” describes the scoping and screening methodology used to identify the SSCs at the Salem Nuclear Generating Station, Units 1 and 2,(Salem) that are within the scope of license renewal and the SCs that are subject to an AMR. The staff reviewed the scoping and screening methodology applied by PSEG Nuclear, LLC (PSEG or the applicant) to determine whether it meets the scoping requirements of 10 CFR 54.4(a) and the screening requirements of 10 CFR 54.21.

In developing the scoping and screening methodology for the LRA, the applicant stated that it considered the requirements of 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” (the Rule); statements of consideration related to the Rule; and the guidance of 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. Additionally, in developing this methodology, the applicant stated that it considered the correspondence between the U.S. Nuclear Regulatory Commission (NRC or the staff), other applicants, and NEI.

2.1.2 Summary of Technical Information in the Application

In LRA Section 2, “Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results,” and LRA Section 3, “Aging Management Review Results,” the applicant provided the technical information required by 10 CFR 54.4, “Scope,” and 10 CFR 54.21(a), “An Integrated Plant Assessment.” In LRA Section 2.1, the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria in accordance with 10 CFR 54.4(a) and the process used to identify the SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1). The applicant provided the results of the process used for identifying the SCs subject to an AMR in the following LRA sections:

(a) LRA Section 2.2, “Plant Level Scoping Results”

(b) LRA Section 2.3, “Scoping and Screening Results: Mechanical”

(c) LRA Section 2.4, “Scoping and Screening Results: Structures”

(d) LRA Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Controls (I&C) Systems”

In LRA Section 3.0, “Aging Management Review Results,” the applicant described its aging management results as follows:

(a) LRA Section 3.1, “Aging Management of Reactor Vessels, Internals, and Reactor Coolant System”

(b) LRA Section 3.2, “Aging Management of Engineered Safety Features”

(c) LRA Section 3.3, “Aging Management of Auxiliary Systems”

(d) LRA Section 3.4, “Aging Management of the Steam and Power Conversion System”

(e) LRA Section 3.5, “Aging Management of Containment, Structures and Component Supports”

(f) LRA Section 3.6, “Aging Management of Electrical and Instrumentation and Controls”

In LRA Section 4.0, “Time-Limited Aging Analyses,” the applicant identified and described the evaluation of time-limited aging analyses (TLAAs).

2.1.3 Scoping and Screening Program Review

The staff evaluated the LRA scoping and screening methodology in accordance with the guidance contained in NUREG-1800, Revision 1, “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 form the basis for the acceptance criteria for the scoping and screening methodology review:

- 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

As part of the review of the applicant’s scoping and screening methodology, the staff reviewed the activities described in the following sections of the LRA using the guidance contained in the SRP-LR:

- Section 2.1, to ensure that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)

- Section 2.2, to ensure that the applicant described a process for determining the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and (a)(2)

In addition, the staff conducted a scoping and screening methodology audit at Salem, located at the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, NJ, during the weeks of January 11–20, 2010. 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 methodologies described in the LRA and the requirements of the Rule. The staff reviewed implementation of the project procedures and technical basis documents describing the applicant's scoping and screening methodology. The staff conducted detailed discussions with the applicant on the implementation and control of the license renewal program and reviewed the administrative control documentation used by the applicant during the scoping and screening process, the quality practices used by the applicant to develop the LRA, and the training and qualification of the LRA development team.

The staff evaluated the quality attributes of the applicant's aging management program (AMP) activities described in LRA Appendix A, "Final Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs." The staff performed a system review of the chemical and volume control system (CVCS), component cooling system, radioactive drain system, auxiliary feedwater (AFW) system, and the turbine building. The staff's review included a review of the applicant's reports on the scoping and screening results and the supporting design documentation used to develop the reports. The purpose of the review was to ensure that the applicant had appropriately implemented the methodology outlined in the administrative controls and to verify that the results are consistent with the current licensing basis (CLB) documentation.

2.1.3.1 Implementing Procedures and Documentation Sources Used for Scoping and Screening

The staff reviewed the applicant's scoping and screening implementing procedures as documented in the scoping and screening methodology audit trip report, dated August 25, 2010 (Agencywide Document Access and Management System (ADAMS) Accession No. ML102280211), to verify that the process used to identify SCs subject to an AMR was consistent with the SRP-LR. Additionally, the staff reviewed the scope of CLB documentation sources and the process used by the applicant to ensure that the applicant's commitments, as documented in the CLB and relative to the requirements of 10 CFR 54.4 and 10 CFR 54.21, were appropriately considered and that the applicant adequately implemented its procedural guidance during the scoping and screening process.

2.1.3.1.1 Summary of Technical Information in the Application

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

- updated final safety analysis report (UFSAR)
- fire hazards analysis report
- environmental qualification master list
- maintenance rule database
- configurations baseline documents

- controlled plant component database
- engineering drawings
- engineering evaluations and calculations
- NRC safety evaluation reports (SERs)
- licensing correspondence

The applicant stated that it used this information to identify the functions performed by each applicable plant system and structure. It then compared these functions to the scoping criteria in 10 CFR 54.4(a)(1)–(3) to determine if the associated plant system or structure performed a license renewal intended function. These sources were also used to develop the list of SCs subject to an AMR.

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 audit report, to ensure the guidance is consistent with the requirements of the Rule, the SRP-LR, and NEI 95-10. The staff finds that the overall process used to implement the 10 CFR Part 54 requirements described in the implementing procedures and AMRs are consistent with the Rule, the SRP-LR, and NEI 95-10.

The applicant's implementing procedures contain guidance for determining plant SSCs within the scope of the Rule and for determining which SCs within the scope of license renewal are subject to an AMR. During the review of the applicant's implementing procedures, the staff focused on the consistency of the detailed procedural guidance with information in the LRA, including the applicant's implementation of NRC staff positions documented in the SRP-LR, and the information in the applicant's responses, dated May 28, 2010, to the staff's requests for additional information (RAIs) dated April 30, 2010.

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. The applicant's methodology has sufficient detail to provide concise guidance on the scoping and screening process to be followed during the implementation of the LRA.

Sources of Current Licensing Basis Information. The staff reviewed 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, as well as SCs requiring an AMR. Pursuant to 10 CFR 54.3(a), the CLB is 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, technical specifications, and design basis information (documented in the most recent UFSAR). The CLB also includes licensee commitments remaining in effect that were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, and licensee commitments documented in NRC safety evaluations or licensee event reports.

During the audit, the staff reviewed pertinent information sources used by the applicant including the UFSAR, design basis information, and license renewal boundary drawings. In addition, the applicant's license renewal process identified additional sources of plant information pertinent to the scoping and screening process, including the fire hazards analysis report, the environmental qualification master list, the maintenance rule database, the configurations baseline documents, controlled plant component database, engineering drawings, engineering evaluations and calculations, and licensing correspondence. The staff verified that the applicant's detailed license renewal program guidelines specified the use of the CLB source information in developing scoping evaluations.

The plant component database, UFSAR, quality classifications, and design basis information were the applicant's primary repository for system identification and component safety classification information used during performance of the scoping evaluations. During the audit, the staff reviewed the applicant's administrative controls for the plant component database, design basis information, and other information sources used to verify system information. These controls are described and implementation is governed by plant administrative procedures. Based on a review of the administrative controls and selected system classification information contained in the applicable Salem documentation, the staff concludes that the applicant has established adequate measures to control the integrity and reliability of Salem system identification and safety classification data. Therefore, the staff concludes that the information sources used by Salem during the scoping and screening process provided a sufficiently controlled source of system and component data to support scoping and screening evaluations.

During the staff's review of the applicant's CLB evaluation process, the applicant discussed the incorporation of updates to the CLB and the process used to ensure those updates are adequately incorporated into the license renewal process. The staff determined that LRA Section 2.1 provides a description of the CLB and related documents used during the scoping and screening process that is consistent with the guidance contained in the SRP-LR.

In addition, the staff reviewed the implementing procedures and results reports used to identify SSCs relied on to demonstrate compliance with the safety-related criteria, nonsafety-related criteria, and the regulated events criteria pursuant to 10 CFR 54.4(a). The applicant's license renewal program guidelines provided a listing of documents used to support scoping and screening evaluations. The staff finds these design documentation sources to be useful in ensuring that the initial scope of SSCs identified by the applicant was 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 audit, the staff concludes that the applicant's scoping and screening methodology considers CLB information in a manner 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 assurance (QA) controls used by the applicant to ensure that scoping and screening methodologies used in the LRA were adequately implemented. The applicant applied the following QA processes during the LRA development:

- Written procedures were developed to govern the implementation of the scoping and screening methodology.
- Scoping and screening summary reports and revisions were prepared, independently verified, and approved.
- Process and procedure self-assessment was performed.
- Scoping and screening self-assessment was performed.
- The license renewal project team performed a self-assessment.
- The LRA was reviewed by the applicant's Challenge Board, the Plant Operations Review Committee, and the Nuclear Safety Review Board.
- The LRA was benchmarked relative to recent applications.
- License renewal management and staff participated in NEI license renewal activities.
- License renewal management and staff participated in external industry reviews.

The staff reviewed the applicant's written procedures and documentation of assessment activities and determined that the applicant had developed adequate procedures to control the LRA development and assess the results of the activities.

2.1.3.2.2 Conclusion

On the basis of its review of pertinent LRA development guidance, discussion with the applicant's license renewal staff, and a review of the applicant's documentation of the activities performed to assess the quality of the LRA, the staff concludes that the applicant's QA 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 applicant's training process to ensure the guidelines and methodology for the scoping and screening activities were applied in a consistent and appropriate manner. As outlined in the implementing procedures, the applicant requires training for all personnel participating in the development of the LRA and uses only trained and qualified personnel to prepare the scoping and screening implementing procedures. The training included the following activities:

- License renewal staff received an initial qualification which consisted of training on the following topics:
    - license renewal process overview
    - license renewal project training and reference materials
    - relevant industry documents
- License renewal staff received additional classroom training on the following topics:
    - site document overview
    - systems and structures overview
    - system specific training
    - database training
- License renewal process overview training was conducted at department staff meetings.

The staff reviewed the applicant's written procedures and reviewed selected completed qualification and training records for the applicant's license renewal personnel. The staff determined that the applicant had developed and implemented adequate procedures to control the training of personnel performing LRA activities.

2.1.3.3.2 Conclusion

On the basis of discussions with the applicant's license renewal project personnel responsible for the scoping and screening process and its review of selected documentation supporting the process, the staff concludes that the applicant's personnel are adequately trained to implement the scoping and screening methodology described in the applicant's implementing procedures and the LRA.

2.1.3.4 Scoping and Screening Program Review Conclusion

On the basis of a review of information provided in LRA Section 2.1, a review of the applicant's detailed scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, 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

In LRA Section 2.1, the applicant described the methodology used to scope SSCs pursuant to the requirements of the 10 CFR 54.4(a) criteria. The LRA states that the scoping process categorized the plant in terms of major systems and structures with respect to license renewal. According to the LRA, major systems and structures were evaluated against criteria provided in 10 CFR Part 54.4(a)(1), (2), and (3) to determine whether the item should be considered within the scope of license renewal. The LRA states that the scoping process identified the SSCs that: (1) are safety-related and perform or support an intended function for responding to a design-basis event (DBE), (2) are nonsafety-related but their failure could prevent accomplishment of a safety-related function, or (3) support a specific requirement for one of the five regulated events applicable to license renewal. LRA Section 2.0, “Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results,” states that the scoping methodology used by Salem is consistent with 10 CFR 54.4 and with the industry guidance contained in NEI 95-10, Revision 6.

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

In LRA Section 2.1.3.2, “Identification of Safety-Related Systems and Structures,” the applicant stated:

> Safety-related systems and structures are included in the scope of license renewal in accordance with 10 CFR 54.4(a)(1) scoping criterion. Salem systems and structures that have been classified as safety-related are identified as “Q” in the controlled quality classification data field in the [Systems, Applications, and Products in Data Processing] SAP database. Salem quality classification procedures were reviewed against the license renewal “Safety-related” scoping criterion in 10 CFR 54.4(a)(1), to confirm that Salem safety-related classifications are consistent with license renewal requirements. This review is included in a technical basis document. The basis document also provides a summary list of the systems and structures that are safety-related at Salem. These systems and structures were included in the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) scoping criteria.

The applicant further stated that the Salem quality classification procedure definition of safety-related is as follows:

> Safety-Related Systems and Components – All systems, and components necessary to ensure the integrity of the reactor coolant pressure boundary; 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 postulated accidents, which could result in potential offsite doses comparable to the guideline exposure of 10 CFR 100, “Reactor Site Criteria.”

The Salem procedure definition does not refer to DBEs, while 10 CFR 54.4(a)(1) refers to DBEs as defined in 10 CFR 50.49(b)(1). For Salem license renewal, an additional technical basis document was prepared to confirm that all applicable DBEs were considered. The basis document includes a review of all systems or structures that fall within the scope of 10 CFR 54.4(a)(1) that are relied upon to remain functional during and following DBEs as defined in 10 CFR 50.49(b)(1). This includes confirming that design basis internal and external events including design-basis accidents (DBAs), anticipated operational occurrences, and natural phenomena as described in the CLB are considered when scoping for license renewal. Safety-related systems and structures required to perform or support 10 CFR 54.4(a)(1) functions are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). Nonsafety-related systems and structures required to perform or support 10 CFR 54.4(a)(1) functions were included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The Salem quality classification procedure definition refers to 10 CFR Part 100 for accident exposure limits. The license renewal rule refers to 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable. These different exposure limit requirements appear in three different code sections to address similar accident analyses performed by licensees for different reasons. The exposure limit requirements in 10 CFR 50.34(a)(1) are applicable to facilities seeking a construction permit and are, therefore, not applicable to Salem license renewal. The exposure limit requirements in 10 CFR 50.67(b)(2) are applicable to facilities seeking to revise the current accident source term used in their design basis radiological analyses. The Salem UFSAR refers to both 10 CFR 50.67 and 10 CFR Part 100 for accident exposure limits. The alternate radiological source term methodology was applied (in accordance with Regulatory Guide (RG) 1.183) to the loss-of-coolant accident (LOCA), steam generator (SG) tube rupture, and fuel handling accident analyses and, therefore, uses 10 CFR 50.67 dose acceptance criteria. Application of alternate radiological source term methodology did not result in changes to the scope of systems classified as safety-related using the Salem quality classification procedure.

When supplemented with the broad review of CLB DBEs, the Salem quality classification procedure definition is consistent with 10 CFR 54.4(a)(1) and results in a comprehensive list of safety-related systems and structures that were included within the scope of license renewal.

2.1.4.1.2 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(1), the applicant must consider all the safety-related SSCs that are relied upon to remain functional during and following a DBE to ensure the following functions: (1) the integrity of the reactor coolant pressure boundary; (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.

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

> The set of DBEs as defined in the Rule is not limited to Chapter 15 (or equivalent) of the UFSAR. Examples of DBEs that may not be described in this chapter include external events, such as floods, storms, earthquakes, tornadoes, or hurricanes, and internal events, such as a high energy line break. Information regarding DBEs 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 SSCs relied upon to remain functional during and following DBEs (as defined in 10 CFR 50.49(b)(1)) to ensure the functions described in 10 CFR 54.4(a)(1).

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

The applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criterion in accordance with the license renewal implementing procedures which provides 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 the applicant's reports of the scoping results to ensure that the applicant applied the methodology in accordance with the implementing procedures. In addition, the staff discussed the methodology and results with the applicant's personnel who were responsible for these evaluations.

The staff reviewed the applicant's evaluation of the Rule and CLB definitions pertaining to 10 CFR 54.4(a)(1) and determined that the CLB definition of safety-related met the definition of safety-related specified in the Rule. The staff reviewed the license renewal scoping results for the CVCS, component cooling system, radioactive drain system, AFW system, and the turbine building to provide additional assurance that the applicant adequately implemented its scoping methodology with respect to 10 CFR 54.4(a)(1). The staff verified that the applicant developed the scoping results for each of the selected systems consistently with the methodology, identified the SSCs credited for performing intended functions, and adequately described the basis for the results, as well as the intended functions. The staff also verified 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.

During review of the LRA and performance of the scoping and screening methodology audit, which was performed onsite during January 11–21, 2010, the staff determined that the scoping implementing procedures discuss the use of the classification "SR," listed in the component classification field in the SAP, as an initial identifier of safety-related systems. In addition, the classification "Q," listed in the component classification field in the SAP, was also used to determine whether systems identified would be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

In RAI 2.1-1, dated April 30, 2010, the staff requested a detailed description of the scoping process with respect to the use of component classification fields in the SAP from the applicant. Specifically, the applicant was asked to explain how the classifications "SR" and "Q" were used to identify safety-related systems.

On May 28, 2010, the applicant stated in response to RAI 2.1-1 that:

> The component design classification information is determined in accordance with the Salem classification methodology procedure SC.DE-AP.ZZ-0061(Q), "Design Classification Methodology for Component Data Module Functional Locations and Systems within SAP/R3 for Salem Generating Station." A total of 48 design classification designations, in the form of alphanumeric codes, are used to identify the classification of components. For example, Q1 through Q20 are used for safety-related components and F1 through F3 are used for fire protection components.
>
> The component design classification designation provides the basis for component classifications identified in SAP, including safety classification (SAF), seismic classification (SEIS), nuclear pipe class (NUCL), quality assurance (QA), and environmental qualification (EQ) requirements. The classification methodology procedure provides the associated definitions and criteria for these

classifications, and Attachment 1 of SC.DE-AP.ZZ-0061(Q), correlates these classifications with the component design classification designation.

The “Safety related QA related” field designates safety-related components at Salem, and is used in the Salem scoping methodology to confirm that all safety-related systems were properly identified and included in scope in accordance with 10 CFR 54.4(a)(1) criteria. A component is designated as safety-related in the SAP database by selecting the “SR” checkbox from the input table for the “Safety related QA related” field. The value of “Safety Related” will display in the “Safety-related QA related” field on the component classification screen in SAP. Safety-related classifications are based on the Salem classification methodology procedure definition of safety related, as described in LRA Section 2.1.3.2.

The QA Required category in SAP identifies safety-related components that are subject to the requirements of 10 CFR 50 Appendix B “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Components designated as “Safety Related” in the “Safety related QA related” SAP field described above, are also designated “Yes” in the “QA Required” field, with the unique exception of design classification designation Q18. The Q18 design classification designation applies specifically to components located in the non-seismic turbine building that serve safety-related functions. Components designated as Q18 are nonsafety related mechanical components subject to augmented quality assurance requirements. These components were identified during the scoping process as nonsafety-related components required to support the accomplishment of a safety-related intended function in accordance with 10 CFR 54.4(a)(1), and were, therefore, included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The staff reviewed the applicant’s response to RAI 2.1-1 and determined that the applicant had used information contained in the component database to identify safety-related components and the parent systems to be evaluated for inclusion within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The applicant’s response indicated that the alpha-numeric Q designations are defined by the Salem component classification methodology procedure SC.DE-AP.ZZ-0061(Q), which was used to classify components meeting the safety-related criteria.

In addition, during review of the LRA and performance of the scoping and screening methodology audit, the staff determined that the 10 CFR 54.4(a)(1) implementing document discusses incorrect or conservative SAP component data module (CDM) classifications. The implementing document provided the process and results of the applicant’s determination that certain systems do not perform safety-related functions as defined in 10 CFR 54.4(a)(1) and were, therefore, not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The staff determined that additional information would be required to complete its review. In RAI 2.1-1, the staff further requested that the applicant provide a detailed description of the process used to evaluate systems or components, identified as safety-related in the SAP, and to conclude that the SAP CDM classifications were conservative or incorrect and that the systems or components do not perform safety-related functions as defined in 10 CFR 54.4(a)(1).

On May 28, 2010, the applicant stated in response to RAI 2.1-1 that:

> It was recognized that this methodology could cause a system to be incorrectly classified as safety-related for license renewal if component classification or component system assignment errors exist in SAP. It was also recognized that for some components in SAP, the component safety-related classification basis is unrelated to the system in which it is assigned in SAP. For example, electrical components in nonsafety-related mechanical systems will be classified safety-related if electrical faults can result in degradation of a safety-related (1 E) power source. The component safety-related classification is, therefore, functionally related to the 1 E power supply system, and is not functionally related to the mechanical system. These electrical components are evaluated with the associated Class 1 E electrical systems, which are also included in scope as safety-related systems.
>
> Results of the SAP component data review were compared to the systems identified as safety-related in the CLB source documents. Some components classified as safety-related in SAP were identified in several systems, where the system is not identified as safety-related or identified as having safety-related intended functions in other CLB source documents, such as the UFSAR and Maintenance Rule system scoping documents. These components were reviewed in detail, and it was determined that these systems should not be identified as safety-related. These determinations are described in detail in the SA-SSBD-A1 basis document. Some cases involved electrical components that were classified as safety-related based on the requirement to protect the connected safety-related power supply system. These safety-related electrical component classifications are not functionally related to the mechanical system, as described earlier. These electrical components are evaluated with the associated Class 1 E electrical systems, which are included in scope as safety-related systems. This case is the result of how some electrical components are assigned to mechanical systems in SAP for plant operation or maintenance purposes, and is not considered a component classification discrepancy.
>
> The remaining cases are associated with SAP component classification discrepancies such as incorrect safety classification, incorrect system assignment, or invalid SAP component identification. In each case, the correct safety classification, system assignment, or other design information was verified from other CLB source documents. Changes to existing system or component safety classifications in the CLB were not required as part of the license renewal scoping process.
>
> The Salem component classification procedure SC.DE-AP.ZZ-0061(Q), "Design Classification Methodology for Component Data Module Functional Locations and Systems within SAP/R3 for Salem Generating Station," requires identification of the applicable plant drawings and CLB source documents used to determine and verify component classification determinations. The SAP component classification discrepancies described above that were identified during the license renewal 10 CFR 54.4(a)(1) scoping reviews were determined to be SAP errors and are not plant design issues, because the correct classifications are identified in the applicable CLB source documents. Actions were initiated to

> notify station personnel and correct the SAP data. SAP errors considered non-conservative or otherwise adverse to quality were entered into the corrective action process to correct the error.

Based on its review, the staff finds the applicant's response to RAI 2.1-1 acceptable because the applicant had described the process used to evaluate systems which contained components identified as safety-related in the SAP and within the scope of license renewal, in accordance with 10 CFR 54.4(a)(1). Also, the staff notes that there could be some components incorrectly classified as safety-related for license renewal if component classification or component system assignment errors exist in the SAP and, for some components in the SAP, the component safety-related classification basis is unrelated to the system in which it is assigned in the SAP. The staff determines that the applicant's methodology for identifying systems and structures is acceptable because if inconsistencies do exist with the SAP, the applicant will verify the correct safety classification, system assignment, or other design information with the CLB source documents and actions will be initiated to notify station personnel and enter the component into the corrective action process to correct the SAP data. The staff's concern described in RAI 2.1-1 is resolved.

2.1.4.1.3 Conclusion

On the basis of its review of systems, discussions with the applicant, review of the applicant's scoping process, and the response to RAI 2.1-1, the staff concludes that the applicant's methodology for identifying systems and structures 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

In LRA Section 2.1.3.3, "10 CFR 54.4(a)(2) Scoping Criteria," the applicant stated:

> All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in accordance with 10 CFR 54.4(a)(1), were included in the scope of license renewal in accordance with 10 CFR 54.4(a)(2) requirements. To assure complete and consistent application of this scoping criterion, a technical basis document was prepared.
>
> This license renewal scoping criterion requires consideration of the following:
>
> 1. Nonsafety-related SSCs required to support a safety-related 10 CFR 54.4(a)(1) function
>
> 2. Nonsafety-related systems connected to and providing structural support for a safety-related SSC
>
> 3. Nonsafety-related systems with a potential for spatial interaction with safety-related SSCs.

In LRA Section 2.1.5.2, "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)," the applicant stated:

> Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions. This category addresses nonsafety-related SSCs that are required to function in support of a safety-related SSC intended function. The functional requirement distinguishes this category from the next two categories, where the nonsafety-related SSCs are required only to maintain adequate integrity to preclude structural failure or spatial interactions. The nonsafety-related SSCs that were included in scope under this review, to support a safety-related SSC in performing its 10 CFR 54.4(a)(1) intended function, are identified on the license renewal boundary drawings in green. The Salem UFSAR and other CLB documents were reviewed to identify nonsafety-related systems or structures credited with supporting satisfactory accomplishment of a safety-related function. Nonsafety-related systems or structures credited in CLB documents to support a safety-related function have been included within the scope of license renewal.
>
> Connected to and Provide Structural Support for Safety-related SSCs. For nonsafety-related piping connected to safety-related piping, the nonsafety-related piping was assumed to provide structural support to the safety-related piping, unless otherwise confirmed by a review of the installation details. The nonsafety-related piping was included in scope for 10 CFR 54.4(a)(2), from the safety-related/nonsafety-related interface, up to one of the following:
>
> A seismic anchor. Only true anchors that ensure forces and moments are restrained in three orthogonal directions are credited.
>
> An anchored component (e.g., pump, heat exchanger, tank, etc.) that is designed not to impose loads on connecting piping. The anchored component is included in scope of license renewal as it has a structural support function for the safety-related piping.
>
> A flexible hose or flexible joint that is not capable of load transfer.
>
> A free end of nonsafety-related piping, such as a drain pipe that ends at an open floor drain.
>
> For nonsafety-related piping runs that are connected at both ends to safety-related piping, the entire run of nonsafety-related piping is included in scope.
>
> A branch line off of a header where the moment of inertia of the header is greater than 15 times the moment of inertia of the branch. The header is treated as an anchor. These scoping boundaries are determined from review of the physical installation details, design drawings or seismic analysis calculations.
>
> Potential for Spatial Interactions with Safety-Related SSCs. Nonsafety-related systems that are not connected to safety-related piping or components, or are beyond the first seismic anchor point past the safety/nonsafety interface, and have a spatial relationship such that their failure could adversely impact the performance of a safety-related SSC intended function, must be evaluated for

license renewal scope in accordance with 10 CFR 54.4(a)(2) requirements. As described in NEI 95-10 Appendix F, there are two options when performing this scoping evaluation: a mitigative option and a preventive option.

The preventive option involves identifying the nonsafety-related SSCs that have a spatial relationship such that failure could adversely impact the performance of a safety-related SSC intended function, and including the identified nonsafety-related SSC in the scope of license renewal without consideration of plant mitigative features. Salem applied the preventive option for 10 CFR 54.4(a)(2) scoping.

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 of SSCs relied on to remain functional during and following a DBE to ensure: (1) the integrity of the reactor coolant pressure boundary, (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: (1) nonsafety-related SSCs typically identified in the CLB; (2) consideration of missiles, cranes, flooding, and high-energy line breaks (HELBs); (3) nonsafety-related SSCs connected to safety-related SSCs; (4) nonsafety-related SSCs in proximity to safety-related SSCs; and (5) mitigative and preventive options related to nonsafety-related and safety-related SSCs interactions.

In addition, as discussed in NEI 95-10, Revision 6, the 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 Sections 2.1.3.3 and 2.1.5.2 in which the applicant described the scoping methodology for nonsafety-related SSCs pursuant to 10 CFR 54.4(a)(2). In addition, the staff reviewed the applicant's implementing document and results report, which documented the guidance and corresponding results of the applicant's scoping review pursuant to 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.

<u>Nonsafety-Related SSCs Required to Perform a Function that Supports a Safety-Related SSC</u>. 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 Sections 2.1.3.3 and 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing document. The staff verified that the applicant had reviewed the UFSAR, plant drawings, plant component 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 verified 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 the LRA and the applicant's 10 CFR 54.4(a)(2) implementing document. The applicant had reviewed the interfaces in each mechanical system between safety-related sections and nonsafety-related sections for the purpose of identifying the nonsafety-related components located between the interface and license renewal 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
- bounding conditions described in NEI 95-10 Revision 6, Appendix F, such as base-mounted component, flexible connection, free end of nonsafety-related piping, or inclusion of the entire nonsafety-related piping run

Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs. The staff verified that nonsafety-related SSCs with the potential for spatial interaction with safety-related 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 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure. The applicant had considered physical impacts (pipe whip, jet impingement) harsh environments, flooding, spray, and leakage when evaluating the potential for spatial interactions between nonsafety-related systems and safety-related SSCs. The staff further verified that the applicant 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 is a scoping process, which involves an evaluation based on equipment location and the related SSCs and whether or not fluid-filled system components are located in the same space as safety-related equipment. A space was defined as a structure containing active or passive safety-related SSCs, for the purposes of the review.

LRA Section 2.1.5.2 and the applicant's implementing document state that the applicant had used a preventive approach, which considered the impact of nonsafety-related SSCs contained in the same space as safety-related SSCs. The staff determined that the applicant had evaluated all nonsafety-related SSCs, containing liquid or steam, and located in spaces containing safety-related SSCs. The applicant used a spaces approach as described above to identify the nonsafety-related SSCs that were located within the same space as safety-related SSCs. In addition, the staff determined that following the identification of the applicable mechanical systems, the applicant identified its corresponding structures for potential spatial interaction, based on a review of the CLB and plant walkdowns. Nonsafety-related systems and components that contain liquid or steam and located inside structures that contain safety-related SSCs were included within the scope of license renewal, unless it was in an excluded space.

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 verified that those nonsafety-related SSCs determined to contain liquid or steam and located within a space containing safety-related SSCs were included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

2.1.4.2.3 Conclusion

On the basis of its review of the applicant's scoping process, discussions with the applicant, and review of the information provided in the response to RAI 2.1-1, the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs, that could affect the performance of safety-related SSCs, within the scope of license renewal, is consistent with the scoping criteria of 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

In LRA Section 2.1.5.3, "Regulated Events – 10 CFR 54.4(a)(3)," the applicant stated:

> For each of the five regulations (i.e., fire protection, environmental qualification, anticipated transients without scram, station blackout, and pressurized thermal shock), a technical basis document was prepared to provide input into the scoping process. Each of the regulated event basis documents identify the systems and structures that are relied upon to demonstrate compliance with the applicable regulation. The basis documents also identify the source documentation used to determine the scope of components within the system that are credited to demonstrate compliance with each of the applicable regulated events. SSCs credited in the regulated events have been classified as satisfying criteria of 10 CFR 54.4(a)(3) and have been included within the scope of license renewal

Fire Protection. In LRA Section 2.1.3.4, "Scoping for Regulated Events," subsection "Fire Protection," the applicant stated:

> All systems, structures and components (SSCs) 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) were included in the scope of license renewal in accordance with 10 CFR 54.4(a)(3) requirements.
>
> The scope of systems and structures required for the fire protection program to comply with the requirements of 10 CFR 50.48 includes:
>
> - systems and structures required to demonstrate post-fire safe shutdown capabilities
> - systems and structures required for fire detection and suppression
> - systems and structures required to meet commitments made to Appendix A of Branch Technical Position (BTP) APCSB 9.5-1

> The fire protection technical basis document summarizes results of a detailed review of the plant's fire protection program documents that demonstrate compliance with the requirements of 10 CFR 50.48. The basis document provides a list of systems and structures credited in the plant's fire protection program documents. For the listed systems and structures, the basis document also identifies appropriate CLB references. The identified systems and structures are included in the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) scoping criteria.

Environmental Qualification. In LRA Section 2.1.3.4, subsection "Environmental Qualification," the applicant stated:

> All 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 Environmental Qualification (10 CFR 50.49) be included in the scope of license renewal.
>
> The Salem Environmental Qualification (EQ) program includes safety-related electrical equipment, nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions of the safety-related equipment, and certain post-accident monitoring equipment, as defined in 10 CFR 50.49(b)(1), 10 CFR 50.49(b)(2), and 10 CFR 50.49(b)(3) respectively. This equipment is included in the scope of license renewal.

Anticipated Transient without Scram. In LRA Section 2.1.3.4, subsection "Anticipated Transients Without Scram," the applicant stated:

> Anticipated Transients Without Scram (ATWS) is a postulated operational transient that generates an automatic scram signal, accompanied by a failure of the reactor protection system to shutdown the reactor. The ATWS rule (10 CFR 50.62) requires improvements in the design and operation of pressurized water reactors [PWR] to reduce the likelihood of failure to shutdown the reactor following anticipated transients, and to mitigate the consequences of an ATWS event. The requirements for a PWR are to have equipment from sensor output to final actuation device, which is diverse from the Reactor Protection System, to automatically initiate the auxiliary feedwater system and initiate a turbine trip under conditions indicative of an ATWS.
>
> The ATWS basis document summarizes the results of a review of the Salem current licensing basis with respect to ATWS. Salem has the ATWS Mitigation System Actuation Circuitry (AMSAC), which comprises a diverse scram system to mitigate the consequences of an ATWS event. The ATWS basis document provides a list of the systems required by 10 CFR 50.62 to reduce the risk from ATWS events. The basis document also provides a list of structures that are credited to provide physical support and protection for the credited ATWS systems. These systems and structures are included in the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) scoping criteria.

Station Blackout. In LRA Section 2.1.3.4, subsection "Station Blackout," the applicant stated:

> Salem implemented plant modifications and procedures in response to 10 CFR 50.63 to enable the station to withstand and recover from a station blackout as an [alternating current] AC-independent, four-hour coping plant. Salem capabilities, commitments and analyses that demonstrate compliance with 10 CFR 50.63 are documented in UFSAR Section 3.12, and in NRC safety evaluation reports and correspondence related to the [station blackout] (SBO) rule.
>
> The NUREG-1800 guidance on scoping of equipment relied on to meet the requirements of the SBO rule (10 CFR 50.63) for license renewal has been incorporated into the Salem scoping methodology. In accordance with the NUREG-1800 requirements, the SSCs required to recover from the SBO event are included in the scope of license renewal. Recovery is defined as the re-powering of the plant AC distribution system from offsite sources or onsite emergency AC sources.
>
> The SBO basis document summarizes the results of a review of the Salem current licensing basis with respect to station blackout. The basis document provides lists of systems and structures credited in Salem SBO evaluations. For the listed systems and structures, the basis document also identifies appropriate CLB references. These systems and structures are included in the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) scoping criteria.

Pressurized Thermal Shock. In LRA Section 2.1.3.4, subsection "Pressurized Thermal Shock," the applicant stated:

> Pressurized Thermal Shock (PTS) is a potential pressurized water reactor (PWR) event or transient causing vessel failure due to severe overcooling (thermal shock) concurrent with, or followed by, significant pressure in the reactor vessel. The CLB shows that the Salem reactor vessel has been demonstrated to meet the toughness requirements of 10 CFR 50.61 through its current 40-year end-of license period. Sixty-year end-of-license fluence projections were prepared, and the components that are projected to meet the definition of beltline material after 60 years of neutron exposure were identified.
>
> The PTS basis document summarizes the results of a review of the Salem current licensing basis with respect to pressurized thermal shock. The basis document identifies components within the Reactor Vessel that are credited in Salem PTS evaluations. The Reactor Vessel is included in the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) scoping criteria.

2.1.4.3.2 Staff Evaluation

The staff reviewed the applicant's approach to identifying SSCs relied upon to perform functions meeting the requirements of the fire protection, EQ, ATWS, SBO, and PTS regulations. As part of this review, the staff discussed the methodology with the applicant, reviewed the documentation developed to support the approach, and evaluated mechanical systems and structures included within the scope of license renewal pursuant to 10 CFR 54.4(a)(3).

Fire Protection. The staff determined that the applicant's implementing procedures indicated that it had included systems and structures within the scope of license renewal required for post-fire safe shutdown, fire detection suppression, and commitments made to Appendix A of BTP APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976," issued May 1976. The applicant noted that it had considered CLB documents to identify systems and structures within the scope of license renewal. These documents included 10 CFR 50, Appendix R, "Fire Study and Salem's Fire Protection Plan"; fire protection systems scoping and screening basis document; fire hazards analysis report; the fire protection program plan as required by 10 CFR 50.48; UFSAR; drawings; and other Salem technical basis documents. The staff reviewed selected scoping results in conjunction with the LRA and the CLB information to validate the methodology for including the appropriate systems and structures within the scope of license renewal. Based on its review of the CLB documents and the selected reviews, the staff determined that the applicant's scoping methodology was adequate for identifying SSCs credited in performing fire protection functions in accordance with 10 CFR 50.48 and within the scope of license renewal.

Environmental Qualification. The staff verified that the applicant's implementing procedures required the inclusion of safety-related electrical equipment, nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishments of safety functions of the safety-related equipment, and certain post-accident monitoring equipment, as defined in 10 CFR 50.49(b)(1), (b)(2), and (b)(3). The staff reviewed the LRA, implementing procedures, the EQ systems scoping and screening basis document and the EQ master component equipment list to verify that the applicant identified SSCs within the scope of license renewal and subject to EQ requirements. Based on that review, the staff determined that the applicant's scoping methodology is adequate for identifying SSCs that meet the requirements of 10 CFR 50.49 within the scope of license renewal.

Anticipated Transient Without Scram. The staff determined that the applicant had generated a list of plant systems credited for ATWS mitigation based on review of the plant and the ATWS systems scoping and screening documents, the UFSAR, docketed correspondence, modifications, and the plant component database. The staff reviewed these documents and the LRA in conjunction with the scoping results to validate the methodology for identifying ATWS systems and structures that are within the scope of license renewal. The staff determined that the applicant's scoping methodology was adequate for identifying SSCs that meet the requirements of 10 CFR 50.62 and are within the scope of license renewal.

Station Blackout. The staff determined that the applicant identified those systems and structures associated with coping and safe shutdown of the plant following an SBO event by reviewing plant-specific SBO systems, scoping and screening basis document calculations, the UFSAR, drawings, modifications, the plant component database, and plant procedures. The staff reviewed selected documents and the LRA in conjunction with the scoping results to validate the applicant's methodology. The staff finds that the scoping results included systems and structures that perform intended functions meeting 10 CFR 50.63 requirements. The staff determined that the applicant's scoping methodology was adequate for identifying SSCs credited as meeting the requirements of 10 CFR 50.63 and are within the scope of license renewal.

Pressurized Thermal Shock. The staff determined that the applicant's scoping methodology had required the applicant to review the activities performed to meet 10 CFR 50.61. As a result of the applicant's methodology, these systems and structures are considered to be within the scope of license renewal pursuant to 10 CFR 54.4(a)(3). The staff reviewed the PTS scoping and screening basis document and the implementing procedure and determined that the methodology was appropriate for identifying SSCs with functions credited for complying with the PTS regulation and within the scope of license renewal. The staff finds that the scoping results included the systems and structures that perform intended functions to meet the requirements of 10 CFR 50.61. Accordingly, the staff determined that the applicant's scoping methodology was adequate for including SSCs that meet the requirements of 10 CFR 50.61 and are within the scope of license renewal.

2.1.4.3.3 Conclusion

On the basis of the discussion with the applicant, review of the LRA, and review of the implementing procedures and reports, the staff concludes that the applicant's methodology for identifying systems and structures meets the scoping criteria pursuant to 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

In LRA Section 2.1, "Scoping and Screening Methodology," the applicant stated:

> The initial step in the scoping process was to define the entire plant in terms of systems and structures. These systems and structures were evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3), to determine if they perform or support a safety-related intended function, or perform functions that demonstrate compliance with the requirements of one of the five license renewal regulated events. For the systems and structures determined to be in scope, the intended functions that are the bases for including the systems and structures in scope were also identified. Scoping evaluations are documented in a System or Structure Scoping Report.
>
> If any portion of a system or structure met the scoping criteria of 10 CFR 54.4, the system or structure was included in the scope of license renewal. Mechanical systems and structures were then further evaluated to determine those mechanical and structural components that perform or support the identified intended functions. The in scope boundaries of mechanical systems and structures were developed. These boundaries are also depicted on the license renewal boundary drawings. The boundaries of the mechanical systems and structures within the scope of license renewal are highlighted in color. In scope structures and mechanical components are shown in green, except nonsafety-related mechanical components that are within the scope of license renewal to preclude physical or spatial interaction, or provide structural support to safety-related SSCs, which are shown in red.
>
> All electrical components within the in scope mechanical and electrical systems were included in the scope of license renewal as electrical commodities. Consequently, further system evaluations to determine which electrical components were required to perform or support the system intended functions were not required.

LRA Section 2.1.2, "Information Sources Used for Scoping and Screening," states that the UFSAR, fire hazards analysis report, EQ master list, maintenance rule database, configuration baseline documents, and controlled plant component database were the primary sources of information used during the scoping process.

LRA Section 2.1.6.3, "Stored Equipment," states that the equipment that is stored on site for installation in response to a DBE is considered to be within the scope of license renewal. At Salem, certain Appendix R fire scenarios used stored equipment to facilitate repairs following the fire. The stored equipment credited for Appendix R repairs are listed in controlled station procedures. These components are confirmed to be available and in good operating condition by periodic surveillance inspections.

LRA Section 2.1.6.4, "Consumables," states that the evaluation process for consumables is consistent with the guidance provided in NUREG-1800, Table 2.1-3. Consumables have been divided into the following four categories for the purpose of license renewal: (1) packing, gaskets, component seals, and O-rings; (2) structural sealants; (3) oil, grease, and component filters; and (4) system filters, fire extinguishers, fire hoses, and airpacks.

2.1.4.4.2 Staff Evaluation

The staff reviewed the applicant's methodology for performing the scoping of plant systems and components to ensure it was consistent with 10 CFR 54.4. The methodology used to determine the systems and components within the scope of license renewal was documented in implementing procedures and scoping results reports for systems. The scoping process defined the plant in terms of systems and structures. Specifically, the implementing procedures identified the systems and structures that are subject to 10 CFR 54.4 review, described the processes for capturing the results of the review, and were used to determine if the system or structure performed intended functions consistent with the criteria of 10 CFR 54.4(a). The process was completed for all systems and structures to ensure that the entire plant was addressed.

The staff reviewed the LRA and applicable implementing procedures that addressed the process used to evaluate stored equipment, credited for response to a DBE, for inclusion within the scope of license renewal. The staff determined that the applicant had appropriately considered stored equipment and included it within the scope of license renewal. In addition, the staff reviewed the LRA and applicable implementing procedures that addressed the process used to evaluate consumables for inclusion within the scope of license renewal. The staff determined that the applicant had appropriately determined that structural sealants were included within the scope of license renewal.

The applicant documented the results of the plant-level scoping process in accordance with the implementing procedures. The results were provided in the systems and structures documents and reports which contained information including a description of the structure or system, a listing of functions performed by the system or structure, identification of intended functions, the 10 CFR 54.4(a) scoping criteria met by the system or structure, references, and the basis for the classification of the system or structure intended functions. During the audit, the staff reviewed selected documents and reports and concluded that the applicant's scoping results contained an appropriate level of detail to document the scoping process.

2.1.4.4.3 Conclusion

Based on its review of the LRA, implementing procedures, reports, and selected system scoping results reviewed during the 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

In addition to the information previously discussed in SER Section 2.1.4.4.1, LRA Section 2.1.5, "Scoping Procedure," states:

> The scoping process is the systematic process used to identify the systems, structures, and components within the scope of the license renewal rule. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions were identified from a review of the source CLB documents. In scope boundaries were established and documented in the scoping evaluations, based on the identified intended functions. The in scope boundaries form the basis for identification of the in scope components, which is the first step in the screening process. System and structure scoping evaluations are documented and have been retained in a license renewal database.

In LRA Section 2.1.5.5, "Scoping Boundary Determination," the applicant stated:

> For mechanical systems, the mechanical components that support the system intended functions are included in the scope of license renewal and are depicted on the applicable system piping and instrumentation diagram. Mechanical system piping and instrumentation diagrams are marked up to create license renewal boundary drawings showing the in scope components. Components that are required to support a safety-related function, or a function that demonstrates compliance with one of the license renewal regulated events, are identified on the system piping and instrumentation diagram by green highlighting. Nonsafety-related components that are connected to safety-related components and are required to provide structural support at the safety/nonsafety interface, or components whose failure could prevent satisfactory accomplishment of a safety-related function due to spatial interaction with safety-related SSCs, are identified by red highlighting. A computer sort and download of associated system components from the SAP database confirms the scope of components in the system. Plant walkdowns were performed when required for additional confirmation.

2.1.4.5.2 Staff Evaluation

The staff used the SRP-LR to evaluate LRA Sections 2.1.5 and 2.1.5.5 and the applicant's guidance in the implementing procedures and reports to perform the review of the mechanical scoping process. The implementing procedures and reports provided instructions for identifying the evaluation boundaries. Information related to system operations in support of the intended functions was necessary to determine the mechanical system evaluation boundary. Based on the review of the implementing procedures and the CLB documents associated with mechanical system scoping, the staff determined that the guidance and CLB source information noted above were consistent with the information in the LRA for identifying mechanical components and support structures in mechanical systems that are 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. 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 LRA Sections 2.1.5 and 2.1.5.5 and the guidance contained in SRP-LR Section 2.1 was adequately implemented.

The staff selected and reviewed the scoping reports for the CVCS, component cooling system, radioactive drain system, and AFW system for mechanical component types that met the scoping criteria of 10 CFR 54.4. The staff verified that the applicant had identified and used pertinent engineering and licensing information in order to determine the mechanical component types required to be within the scope of license renewal. As part of the review process, the staff evaluated: (1) each system's intended functions identified for the CVCS, component cooling system, radioactive drain system, and AFW system; (2) the basis for inclusion of the intended function; and (3) the process used to identify each of the system component types. The staff verified that the applicant had identified and highlighted system drawings to develop the license renewal boundaries in accordance with the procedural guidance. Additionally, the staff determined that the applicant had performed an independent verification of the results in accordance with the governing procedures. The staff verified that the applicant had license renewal personnel knowledgeable about the system and these personnel had performed independent reviews of the highlighted drawings to ensure accurate identification of system intended functions. The staff also verified that the applicant had performed additional cross-discipline verification and independent reviews of the resultant highlighted drawings before final approval of the scoping effort.

2.1.4.5.3 Conclusion

On the basis of its review of the LRA and supporting documents, discussion with the applicant, and the system review of mechanical scoping results, the staff concludes that the applicant's methodology for identifying mechanical SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.6 Structural Component Scoping

2.1.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.1.5, the applicant stated:

> The scoping process is the systematic process used to identify the systems, structures and components within the scope of the license renewal rule. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions were identified from a review of the source CLB documents. In scope boundaries were established and documented

> in the scoping evaluations, based on the identified intended functions. The in scope boundaries form the basis for identification of the in scope components, which is the first step in the screening process. System and structure scoping evaluations are documented and have been retained in a license renewal database.

In LRA Section 2.1.5.5, the applicant stated:

> For structures, the structural components that support the intended functions are included in the scope of license renewal. The structural components are identified from a review of applicable plant design drawings of the structure. Plant walkdowns were performed when required for additional confirmation. A single site plan layout drawing is marked up to create a license renewal boundary drawing showing the structures in the scope of license renewal.

2.1.4.6.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.5 and 2.1.5.5, and subsections, and the guidance contained in the applicant's implementing procedures and reports to perform the review of the structural scoping process. The staff reviewed the applicant's approach for identifying structures relied upon to perform the functions described in 10 CFR 54.4(a). As part of this review, the staff discussed the methodology with the applicant, reviewed the documentation developed to support the review, and evaluated the scoping results for selected structures that were identified within the scope of license renewal. The staff determined that the applicant had identified and developed a list of plant structures and the structures' intended functions through a review of the plant component database, the Structures Monitoring Program, UFSAR, controlled drawings, maintenance procedures, and walkdowns. Each structure the applicant identified was evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

The staff reviewed selected portions of the plant component database, UFSAR, drawings, procedures, and implementing procedures to verify the adequacy of the methodology. The staff selected and reviewed the source documentation for the turbine building to verify that the application of the methodology would provide the results as documented in the turbine building scoping report and in the LRA. The staff verified that the applicant had identified and used pertinent engineering and licensing information in order to determine that the turbine building was required to be included within the scope of license renewal. In addition, during the scoping and screening methodology audit, the staff performed walkdowns of selected areas of the turbine building to verify proper implementation of the scoping process. As part of the review process, the staff evaluated the intended functions identified for the turbine building and the structural components, the basis for inclusion of the intended function, and the process used to identify each of the component types.

2.1.4.6.3 Conclusion

On the basis of its review of information in the LRA and supporting documents, implementing procedures, and structural scoping results, the staff concludes that the applicant's methodology for identification of the structural SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.1.5, the applicant stated:

> The scoping process is the systematic process used to identify the systems, structures and components within the scope of the license renewal rule. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions were identified from a review of the source CLB documents. In scope boundaries were established and documented in the scoping evaluations, based on the identified intended functions. The in scope boundaries form the basis for identification of the in scope components, which is the first step in the screening process. System and structure scoping evaluations are documented and have been retained in a license renewal database.

In LRA Section 2.1.5.5, the applicant stated:

> Electrical and I&C systems, and electrical components within mechanical systems, did not require further system evaluations to determine which components were required to perform or support the identified intended functions. A bounding scoping approach is used for electrical equipment. All electrical components within in scope systems were included in the scope of license renewal. In scope electrical components were placed into commodity groups and were evaluated as commodities during the screening process.

2.1.4.7.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.5 and 2.1.5.5, and subsections, and the guidance contained in the applicant's implementing procedures and reports to perform the review of the electrical scoping process. The staff reviewed the applicant's approach to identifying electrical and I&C SSCs relied upon to perform the functions described in 10 CFR 54.4(a). The staff reviewed portions of the documentation used by the applicant to perform the electrical scoping process including the UFSAR, plant component database, CLB documentation, drawings, and specifications. As part of this review, the staff discussed the methodology with the applicant, reviewed the implementing procedures developed to support the review, and evaluated the scoping results for selected SSCs that were identified within the scope of license renewal. The staff determined that the applicant had included electrical and instrument control components, including components contained in the mechanical or structural systems, within the scope of license renewal on a commodity basis.

2.1.4.7.3 Conclusion

On the basis of its review of information contained in the LRA, implementing procedures and supporting documents, discussions with the applicant, and a review of selected electrical scoping results, the staff concludes that the applicant's methodology for the identification of electrical and I&C SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.8 Scoping Methodology Conclusion

On the basis of its review of the LRA, implementing procedures, and a review of selected scoping results, the staff concludes that the applicant's scoping methodology was consistent with the guidance contained in the SRP-LR and identified those SSCs: (1) that are safety-related, (2) whose failure could affect safety-related functions, and (3) that are necessary to demonstrate compliance with the NRC regulations for fire protection, EQ, PTS, 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

2.1.5.1.1 Summary of Technical Information in the Application

LRA Section 2.1.6.1, "Identification of Structures and Components Subject to AMR," and subsections, describes the screening process that identifies the SCs within the scope of license renewal that are subject to an AMR. In LRA Section 2.1.6.1, the applicant stated:

> Structures and components that perform an intended function without moving parts or without a change in configuration or properties are defined as passive for license renewal. Passive structures and components that are not subject to replacement based on a qualified life or specified time period are defined as long-lived for license renewal. The screening procedure is the process used to identify the passive, long-lived structures and components in the scope of license renewal and subject to aging management review.
>
> NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" and NEI 95-10, Appendix B were used as the basis for the identification of passive structures and components. Most passive structures and components are long-lived. In the few cases where a passive component is determined not to be long-lived, such determination is documented in the screening evaluation and, if applicable, on the associated license renewal boundary drawing. The Salem structures and components subject to AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1) described above.

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 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 determine the 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 used by the applicant to identify the mechanical and structural components and electrical commodity groups within the scope of license renewal that should be 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). In LRA Section 2.1.6.1, the applicant discussed these screening activities as they relate to the component types and commodity groups within the scope of license renewal.

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 LRA Section 2.3, “Scoping and Screening Results: Mechanical”; LRA Section 2.4, “Scoping and Screening Results: Containment, Structures and Components Supports”; and LRA Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Controls (I&C) Systems.” These LRA sections provide the results of the process used to identify component types and commodity groups subject to an AMR. 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. The staff also reviewed the screening results reports for the CVCS, component cooling system, radioactive drain system, AFW system, and the turbine building.

2.1.5.1.3 Conclusion

On the basis of its review of the LRA, the implementing procedures, and selected screening results, the staff concludes that the applicant’s screening methodology was consistent with the guidance contained in the SRP-LR and was capable of identifying passive, long-lived components within the scope of license renewal that are subject to an AMR. The staff concludes that the applicant’s process for determining which component types and commodity groups 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

In LRA Section 2.1.6.1, “Identification of Structures and Components Subject to AMR,” the applicant stated:

> For in scope mechanical systems, the completed scoping packages include written descriptions and marked up system piping and instrumentation diagrams that clearly identify the in scope system boundary for license renewal. The marked up system piping and instrumentation diagrams are called boundary drawings for license renewal. These system boundary drawings were carefully reviewed to identify the passive, long-lived components, and the identified components were then entered into the license renewal database. Component listings from the SAP database were also reviewed to confirm that all system components were considered. In cases where the system piping and instrumentation diagram did not provide sufficient detail, such as for some large vendor supplied components (e.g., compressors, emergency diesel generators), the associated component drawings or vendor manuals were also reviewed. Plant walkdowns were performed when required for confirmation. Finally, the identified list of passive, long-lived system components was benchmarked against previous license renewal applications containing a similar system.

2.1.5.2.2 Staff Evaluation

The staff reviewed the mechanical screening methodology discussed and documented in LRA Section 2.1.6.1, implementing procedures, scoping and screening reports, and license renewal drawings. The staff determined that the mechanical system screening process used the results from the scoping process and that the applicant reviewed each system evaluation boundary as depicted on system drawings to identify passive and long-lived components.

Additionally, the staff determined that the applicant had identified all passive and long-lived components that perform or support an intended function within the system evaluation boundaries and determined those components to be subject to an AMR. The results of the review were documented in the scoping and screening reports, which contain the information sources reviewed and the component-intended functions.

The staff verified that mechanical system evaluation boundaries were established for each system within the scope of license renewal and that the boundaries were determined by mapping the system-intended function boundary onto system drawings. The staff verified that the applicant reviewed the components within the system-intended function boundary to determine if the component supported the system-intended function and that those components that supported the system intended function were reviewed to determine if the component was passive and long-lived and, therefore, subject to an AMR.

The staff reviewed portions of the UFSAR, plant component database, CLB documentation, procedures, drawings, specifications, and selected scoping and screening reports. The staff conducted detailed discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff assessed whether the mechanical screening methodology outlined in the LRA and implementing procedures was appropriately implemented and if the scoping results were consistent with CLB requirements. During the scoping and screening methodology audit, the staff discussed the screening methodology with the applicant and reviewed the applicant's screening reports for the CVCS, component cooling system, radioactive drain system, and AFW system to verify proper implementation of the screening process. In addition, the staff performed walkdowns of selected portions of the systems as an example of the methodology and its implementation. Based on these activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.2.3 Conclusion

On the basis of its review of the LRA, the screening implementation procedures, selected portions of the UFSAR, plant component database, CLB documentation, procedures, drawings, specifications, selected scoping and screening reports, and a review of the results for selected systems, the staff concludes that the applicant's methodology for identification of mechanical 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.

2.1.5.3 Structural Component Screening

2.1.5.3.1 Technical Information in the Application

In LRA Section 2.1.6.1, the applicant stated:

> For in scope structures, the completed scoping packages include written descriptions of the structure. If only selected portions of the structure are in scope, the in scope portions are described in the scoping evaluation. The associated structure drawings were carefully reviewed to identify the passive, long-lived structures and components, and the identified structures and components were then entered into the license renewal database. Component listings from the SAP database were also reviewed to confirm that all structural components were considered. Plant walkdowns were performed when required for confirmation. Finally, the identified list of passive, long-lived structures and components was benchmarked against previous license renewal applications.

2.1.5.3.2 Staff Evaluation

The staff reviewed the structural screening methodology discussed and documented in LRA Section 2.1.6, the implementing procedures, and the license renewal drawings. The staff reviewed the applicant’s methodology for identifying structural components that are subject to an AMR as required in 10 CFR 54.21(a)(1). The staff verified that the applicant had reviewed the structures included within the scope of license renewal and identified the passive, long-lived components with component-level intended functions and determined those components to be subject to an AMR.

The staff reviewed selected portions of the UFSAR, the Structures Monitoring Program, and scoping and screening reports, which the applicant had used to perform the structural scoping and screening activities. The staff also reviewed the structural drawings to document the SCs within the scope of license renewal and subject to an AMR. The staff conducted discussions with the applicant’s license renewal team and reviewed documentation pertinent to the screening process to assess if the screening methodology outlined in the LRA and implementing procedures were appropriately implemented and if the screening results were consistent with the CLB requirements. In addition, during the scoping and screening methodology audit, the staff reviewed the turbine building to verify proper implementation of the screening process and performed walkdowns of selected areas. Based on the review activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.3.3 Conclusion

On the basis of its review of the LRA, implementation procedures, the UFSAR, plant component database, CLB documentation, drawings, specifications and selected scoping and screening reports, discussion with the applicant, and the results of the screening methodology, the staff concludes that the 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

In LRA Section 2.1.6.1, “Identification of Structures and Components Subject to AMR,” the applicant stated:

> Screening of electrical and I&C components used a bounding approach as described in NEI 95-10. Electrical commodity groups were identified without regard to system. Electrical and I&C components/commodity groups are subject to aging management review, unless they are determined to not be in scope at the system level. The commodity groups subject to an AMR are identified by applying the criteria of 10 CFR 54.21(a)(1). This method provides the most efficient means for determining the electrical commodity groups subject to an AMR since many electrical and I&C components/commodity groups are active. The sequence of steps and special considerations for identification of electrical components that require an AMR is as follows:
>
> - Electrical and I&C components in within scope systems at Salem were identified and listed. The electrical and I&C component commodity groups were identified from a review of plant documents, controlled drawings, the plant component database (SAP), and interface with the parallel mechanical and civil/structural screening efforts.
>
> - Following the identification of the electrical component commodity groups, the criterion of 10 CFR 54.21(a)(1)(i) was applied to identify component commodity groups that perform their functions without moving parts or without a change in configuration or properties (referred to as “passive” components). These components were identified utilizing the guidance of NEI 95-10 and the [Electric Power Research Institute] EPRI License Renewal Electrical Handbook.
>
> - The screening criterion found in 10 CFR 54.21(a)(1)(ii) excludes those components or commodity groups that are subject to replacement based on a qualified life or specific time period from the requirements of an aging management review. The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to those components and commodity groups that were not previously eliminated by the application of the 10 CFR 54.21(a)(1)(i) screening criterion.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant’s methodology used for electrical screening in LRA Section 2.1.6.1 and subsections, implementing procedures, bases documents, and reports. The staff verified 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 I&C components subject to an AMR.

The staff determined that the applicant had identified commodity groups which were found to meet the passive criteria in accordance with NEI 95-10. In addition, the staff determined that the applicant evaluated and identified passive commodities on 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). The applicant had correctly determined the remaining passive, long-lived components to be subject to an AMR.

The staff reviewed selected portions of the UFSAR, the plant component database, the CLB documentation, documents, procedures, drawings, specifications, and selected scoping and screening reports. The staff conducted detailed discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff assessed whether the electrical screening methodology outlined in the LRA and procedures were appropriately implemented and if the scoping results were consistent with CLB requirements. During the scoping and screening methodology audit, the staff discussed the screening methodology with the applicant and reviewed the applicant's screening reports for selected systems to verify proper implementation of the screening process. Based on these audit activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.4.3 Conclusion

On the basis of its review of the LRA, implementing procedures, selected portions of the UFSAR, plant component database, CLB documentation, procedures, drawings, specifications and selected scoping and screening reports, discussion with the applicant, and 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 Screening Methodology Conclusion

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

2.1.6 Summary of Evaluation Findings

On the basis of its review of the information presented in LRA Section 2.1, the supporting information in the scoping and screening implementing procedures and reports, the information presented during the scoping and screening methodology audit, discussions with the applicant, selected system reviews, and the applicant's response dated May 28, 2010, to the staff's RAIs, the staff concludes that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4. 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

LRA Section 2.1 describes the methodology for identifying systems and structures within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which systems and structures 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 the following three groups:

- 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).
- 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

LRA Table 2.2-1 lists those mechanical systems, electrical and I&C systems, and structures that are within the scope of license renewal. Also in LRA Table 2.2-1, the applicant listed the systems and structures that do not meet the criteria specified in 10 CFR 54.4(a) and are excluded from the scope of license renewal. Based on the DBEs considered in the 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

The purpose of the staff's evaluation was to determine whether the applicant properly identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

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 SER Section 2.1. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results shown in LRA Table 2.2-1 to confirm that there were no omissions of plant-level systems and structures that should be 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 determine 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." The staff reviewed LRA Section 2.2 and the UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal.

2.2.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has appropriately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 Scoping and Screening Results: Mechanical Systems

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

- reactor vessel, internals, and reactor coolant system
- engineered safety features
- 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 verify that the applicant identified the mechanical system SCs that met the scoping criteria and were subject to an AMR, confirming that there were no omissions. The staff's evaluation of mechanical systems was performed using the evaluation methodology described in this SER and in the guidance in SRP-LR Section 2.3, and took into account where applicable, the system function(s) described in the UFSAR. 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 meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components are subject to an AMR as required by 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the LRA, applicable sections of the UFSAR, license renewal boundary drawings, and other licensing basis documents, as appropriate, for each mechanical system within the scope of license renewal. The staff reviewed relevant licensing basis documents for each mechanical system to confirm that the LRA specified all intended functions defined by 10 CFR 54.4(a). The review then focused on identifying any components with intended functions defined by 10 CFR 54.4(a) that the applicant may have omitted from the scope of license renewal.

After reviewing the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions delineated in accordance with 10 CFR 54.4(a), the staff verified the applicant properly screened out only: (1) SCs that have functions performed with moving parts or a change in configuration or properties or (2) SCs that are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For SCs not meeting either of these criteria, the staff verified the remaining SCs received an AMR, as required by 10 CFR 54.21(a)(1).

The staff evaluation of the mechanical system scoping and screening results applies to all mechanical systems reviewed. Those systems that required RAIs to be generated (if any) include an additional staff evaluation which specifically addresses the applicant's response to the RAI(s).

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

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

- 2.3.1.1 reactor coolant system
- 2.3.1.2 reactor vessel
- 2.3.1.3 reactor vessel internals
- 2.3.1.4 SGs

2.3.1.1 Reactor Coolant System

2.3.1.1.1 Summary of Technical Information in the Application

LRA Section 2.3.1.1 describes the RCS, which is a normally operating system designed to circulate sub-cooled reactor coolant to transfer heat from the reactor core to the secondary fluid in four SGs during normal operation and anticipated operational occurrences. The system is capable of transferring this heat using forced circulation with the reactor coolant pumps (RCPs) during normal operation, or using natural circulation when necessary during emergency operations. The RCS also contains the RV level instrumentation. The RCS consists of the following major components: pressurizer, reactor coolant pressure boundary components (hot leg piping and cold leg piping), RCPs and their oil lift system, pressurizer relief tank, pressurizer heaters, pressurizer surge line, pressurizer spray line, and the reactor head vent piping. RV level instrumentation consists of two redundant trains of hydraulic components and instrumentation.

LRA Table 2.3.1-1 identifies the components subject to an AMR for the RCS by component type and intended function.

2.3.1.1.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RCS mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Vessel

2.3.1.2.1 Summary of Technical Information in the Application

LRA Section 2.3.1.2 describes the RV system, which is a normally operating system designed to contain the pressure and heat in the core and transfer this heat to the reactor coolant. The RV system consists of the following major components: the RV, the integrated head assembly, control rod drive mechanisms, the attached vent, flange leak-off, drain, level instrumentation piping and components, the vessel shells, upper shell flange, nozzle shell course, nozzles, safe ends, closure studs, the lower head, the core support lug, and the primary nozzle supports.

The purpose of the RV system is to maintain the RV pressure boundary and provide structural support for the RV internals, core, and control rod drive mechanisms. The control rod drive system is used to insert negative reactivity into the reactor core. The RV also provides a pressure boundary for fluid in the vessel and acts as a boundary to preclude fission products from entering the environment.

LRA Table 2.3.1-2 identifies the components subject to an AMR for the RV system by component type and intended function.

2.3.1.2.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RV system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessel Internals

2.3.1.3.1 Summary of Technical Information in the Application

LRA Section 2.3.1.3 describes the RV internals system, which is a normally operating system designed to maintain the reactor core assembly geometry, maintain the reactor core subcritical for any mode of operation or DBE, and introduce negative reactivity to make the reactor subcritical. The RV internals consist of the upper core support structure, the lower core support structure, and the incore instrumentation support structure. Also included are the flux thimble tubes, fuel assemblies, and the rod cluster control assemblies.

The overall purpose of the RV internals is to direct reactor coolant through the core to achieve acceptable flow distribution and restrict bypass flow, so that heat transfer performance requirements are met during all modes of operation. The upper core support structure is used to provide structural support and contain the guide tube assemblies that shield and guide the control rod drive shafts and control rods. The lower core support structure provides structural support for vertical loads, forms a periphery enclosure of the core including core baffles and a bottom flow distribution plate for efficient flow distribution, and provides neutron shielding by means of the thermal shield. The incore instrumentation support structure is used to provide structural support for the bottom-mounted incore instrumentation (flux thimbles and thermocouples) and to maintain a pressure boundary between the reactor coolant and the containment atmosphere.

The purpose of the fuel assemblies is to: (1) generate heat from the fuel rods, (2) maintain a coolable fuel rod geometry, and (3) promote efficient heat transfer from the nuclear fuel to the reactor coolant. The rod cluster control assemblies are used to provide reactivity control for shutdown, control reactivity changes resulting from reactor coolant temperature changes, control the power coefficient of reactivity, and also control void formation.

LRA Table 2.3.1-3 identifies the components subject to an AMR for the RV internals by component type and intended function.

2.3.1.3.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RV internals system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Steam Generators

2.3.1.4.1 Summary of Technical Information in the Application

LRA Section 2.3.1.4 describes the SGs, which are a normally operating system designed to serve as a heat sink for the reactor coolant and provide a barrier to prevent fission products and activated corrosion products in the reactor coolant from entering the steam system. The SGs consist of the following plant systems: SGs and SG drains and blowdown. The major components of the SGs are the four SGs per unit. Unit 1 has Westinghouse Model F recirculating SGs. Unit 2 has AREVA 61/19T recirculating SGs.

The purposes of the SGs are to: (1) to transfer heat from the reactor coolant to the main feedwater via the four recirculating SGs during normal operation and anticipated operational occurrences so that reactor core thermal limits are not exceeded, (2) to provide a pressure boundary to separate fission products from the environment, and (3) to provide containment isolation.

LRA Table 2.3.1-4 identifies the components subject to an AMR for the SGs by component type and intended function.

2.3.1.4.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the SG system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 describes the engineered safety features system SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the engineered safety features system in the following LRA sections:

- 2.3.2.1 containment spray system
- 2.3.2.2 residual heat removal system
- 2.3.2.3 safety injection system

2.3.2.1 Containment Spray System

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the containment spray system, which is a mechanical, standby system designed to reduce containment pressure to nearly atmospheric pressure, remove airborne fission products from the containment atmosphere, minimize corrosion of equipment following a large-break loss-of-coolant accident (LBLOCA), and limit containment pressure following a main steamline break (MSLB) inside the containment structure. The containment spray system is comprised of two redundant loops. Each loop consists of one containment spray pump, one eductor, two sets of nozzles, and the necessary piping, valves, instrumentation, and controls.

The purpose of the containment spray system is to remove energy from the environment by transferring heat from the higher temperature atmosphere to the lower temperature spray droplets discharged from the containment spray nozzles.

LRA Table 2.3.2-1 identifies the components subject to an AMR for the containment spray system by component type and intended function.

2.3.2.1.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the containment spray system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Residual Heat Removal System

2.3.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 describes the residual heat removal (RHR) system, which is a standby, mechanical emergency core cooling system (ECCS) designed to provide low pressure injection flow and long-term core cooling following a DBE. The RHR system is comprised of two RHR pumps, two RHR heat exchangers, one letdown booster pump, the containment sump, and the associated piping, valves, instrumentation, and controls.

The purpose of the RHR system is to: (1) remove decay heat from the core and residual heat from the RCS during the latter stages of a plant cooldown, (2) maintain the reactor coolant temperature during refueling, and (3) provide a means for filling and draining the reactor cavity and fuel transfer canal during refueling. In the event of a LOCA, the system injects borated water into the RV.

LRA Table 2.3.2-2 identifies the components subject to an AMR for the RHR system by component type and intended function.

2.3.2.2.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RHR system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Safety Injection System

2.3.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 describes the safety injection system, which is a standby, intermediate-pressure ECCS designed to provide emergency core cooling following a LOCA or MSLB in the containment structure. The safety injection system is one part of the ECCS along with the RHR system and the CVCS. The ECCS consists of the following components: centrifugal charging pumps, RHR pumps, safety injection pumps, safety injection accumulators, boron injection tank, refueling water storage tank (RWST), and the necessary piping, valves, controls, and instrumentation.

The purpose of the safety injection system is to: (1) provide core cooling by injecting borated water from the RWST into the core following a LOCA or MSLB, (2) provide core reflooding during an LBLOCA by injecting borated water from the safety injection accumulators, and (3) provide containment isolation for piping penetrations following a DBE.

LRA Table 2.3.2-3 identifies the components subject to an AMR for the safety injection system by component type and intended function.

2.3.2.3.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the safety injection system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 system SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the auxiliary systems in the following LRA sections:

- 2.3.3.1 auxiliary building ventilation system
- 2.3.3.2 chemical and volume control system
- 2.3.3.3 chilled water system
- 2.3.3.4 circulating water system
- 2.3.3.5 component cooling system
- 2.3.3.6 compressed air system

- 2.3.3.7 containment ventilation system
- 2.3.3.8 control area ventilation system
- 2.3.3.9 cranes and hoists
- 2.3.3.10 demineralized water system
- 2.3.3.11 emergency diesel generators and auxiliary systems
- 2.3.3.12 fire protection system
- 2.3.3.13 fresh water system
- 2.3.3.14 fuel handling and fuel storage system
- 2.3.3.15 fuel handling ventilation system
- 2.3.3.16 fuel oil system
- 2.3.3.17 heating water & heating steam system
- 2.3.3.18 non-radioactive drain system
- 2.3.3.19 radiation monitoring system
- 2.3.3.20 radioactive drain system
- 2.3.3.21 radwaste system
- 2.3.3.22 sampling system
- 2.3.3.23 service water system
- 2.3.3.24 service water ventilation system
- 2.3.3.25 spent fuel cooling system
- 2.3.3.26 switchgear and penetration area ventilation system

Auxiliary Systems Generic Requests for Additional Information. On April 14, 2010, the staff, in RAI 2.3-01, requested that the applicant provide information enabling the staff to locate the missing continuation drawings and explain some inconsistencies in the license renewal drawings. On May 12, 2010, the applicant provided the necessary drawing and explanations of the inconsistencies.

Based on its review, the staff finds the applicant's response to RAI 2.3-01 acceptable because the applicant provided the continuation locations or a description, including component types, to the license renewal boundary. Therefore, the staff's concern described in RAI 2.3-01 is resolved.

2.3.3.1 Auxiliary Building Ventilation System

2.3.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 describes the auxiliary building ventilation system, which is a mechanical, normally operating, once-through heating and ventilating system for each unit designed for long-term continuous operation during normal and emergency modes of plant operation.

The purpose of the auxiliary building ventilation system is to control air temperature and air cleanliness and maintain a negative pressure within selected areas in the auxiliary building during normal and emergency modes of plant operation.

LRA Table 2.3.3-1 identifies the components subject to an AMR for the auxiliary building ventilation system by component type and intended function.

2.3.3.1.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the auxiliary building ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Chemical and Volume Control System

2.3.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 describes the CVCS which consists of the following plant systems: (1) the CVCS, (2) the boric acid recovery system, and (3) the primary water recovery system. The CVCS is a normally operating mechanical system designed to control the inventory of the RCS during all phases of normal reactor operation.

The main purpose of the CVCS is to: (1) inject borated water from the RWST into the reactor core following a LOCA for emergency cooling, (2) control the boric acid concentration in the reactor coolant for reactivity management, (3) control the reactor coolant inventory during all phases of reactor operations including hydrostatic testing of the RCS, (4) provide for purification of the reactor coolant to remove corrosion and fission products, (5) provide makeup to the RWST and spent fuel pool, (6) provide seal injection water for the RCP seals, and (7) vent gases from the RCS.

LRA Table 2.3.3-2 identifies the components subject to an AMR for the CVCS by component type and intended function.

2.3.3.2.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the CVCS mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Chilled Water System

2.3.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 describes the chilled water system which consists of the following plant systems: (1) the auxiliary building, (2) the administration building, (3) the clean facilities building, (4) the controlled facilities building, (5) the secondary chemistry laboratory, and (6) the service building. The chilled water system is a normally operating, mechanical system designed to provide cooling to safety-related and nonsafety-related ventilation systems.

The purpose of the chilled water system is to provide cooling water to the control room ventilation coils, nonsafety-related areas, and sampling heat exchangers.

LRA Table 2.3.3-3 identifies the components subject to an AMR for the chilled water system by component type and intended function.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3, UFSAR Sections 9.4.1.2 and 9.3.1.2, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In RAI 2.3.3.3-01, dated April 14, 2010, the staff noted that Unit 1 license renewal drawing LR-205216, sheet 1, at three locations, shows a change of scope classification from 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2) after the ⅛-inch diameter orifices near valves 1CH28, 1CH6, and 1CH20. The piping class break is shown downstream of the ⅛-inch diameter orifices. The inclusion of safety-related piping within scope for 10 CFR 54.4(a)(2) would conflict with the scoping procedure described in LRA Section 2.1.5.1. The applicant was requested to provide additional information to clarify these scoping classifications.

In its response dated May 12, 2010, the applicant stated that the piping on the downstream side of the ⅛-inch restricting orifices through the drain lines, including the automatic vacuum relief valves, are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The license renewal scoping boundary is shown correctly as described on license renewal drawing LR-205216, sheet 1. The restricting orifices provide adequate isolation of the safety-related chilled water system equipment from the nonsafety-related drain system. The drain lines on the downstream side of the restricting orifices are not required to perform any 10 CFR 54.4(a)(1) function and are, therefore, not within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The drawing is revised to show the piping classification break at the outlet of the orifice. The drain lines on the downstream side of the restricting orifices contain water and, therefore, are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-01 acceptable because the applicant clarified the scoping classification of the pipe lines in question. The staff agrees that the restricting orifices provide adequate isolation of the safety-related chilled water system equipment from the nonsafety-related drain system and the drain lines on the downstream side of the restricting orifices contain water and, therefore, are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction with safety-related components. Therefore, the staff's concern described in RAI 2.3.3.3-01 is resolved.

In RAI 2.3.3.3-02 dated April 14, 2010, the staff noted that Unit 2 license renewal drawing LR-205216, sheet 2, at three locations, shows a change of scope classification from 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2) after the ⅛-inch diameter orifices near valves 2CH28, 2CH20, and 2CH6. The piping class break is shown downstream of the ⅛-inch diameter orifices. The inclusion of safety-related piping within scope for 10 CFR 54.4(a)(2) would conflict with the scoping procedure described in LRA Section 2.1.5.1. The applicant was requested to provide additional information to clarify these scoping classifications.

In its response dated May 12, 2010, the applicant stated that the piping on the downstream side of the ⅛-inch restricting orifices through the drain lines, including the automatic vacuum relief valves, are shown as red and within the scope of license renewal in accordance with

10 CFR 54.4(a)(2). The license renewal scoping boundary is shown correctly as described above on license renewal drawing LR-205216, sheet 2. The restricting orifices provide adequate isolation of the safety-related chilled water system equipment from the nonsafety-related drain system. The drain lines on the downstream side of the restricting orifices are not required to perform any 10 CFR 54.4(a)(1) function and are, therefore, not within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The drawing is revised to show the piping classification break at the outlet of the orifice. The drain lines on the downstream side of the restricting orifices contain water and, therefore, are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-02 acceptable because the applicant clarified the scoping classification of the pipe lines in question. The staff agrees that the restricting orifices provide adequate isolation of the safety-related chilled water system equipment from the nonsafety-related drain system and the drain lines on the downstream side of the restricting orifices contain water and, therefore, are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction with safety-related components. Therefore, the staff's concern described in RAI 2.3.3.3-02 is resolved.

In RAI 2.3.3.3-03, dated April 14, 2010, the staff noted license renewal drawing LR-205216, sheet 1 showed lines 2-inch-1CH1143 and 2-inch-1CH1142 out of the No. 1 expansion tank (1CHE1) as within the scope of license renewal for 10 CFR 54.4(a)(1), whereas similar lines 2-inch-2CH1105 and 2-inch-2CH110 out of the No. 2 expansion tank (2CHE8) on license renewal drawing LR-205216, sheet 2 are shown within scope for 10 CFR 54.4(a)(2). The applicant was requested to provide additional information explaining why there is a difference in scope classification in similar lines.

In its response dated May 12, 2010, the applicant stated that there are two level indicators on the No. 1 expansion tank. One level indicator is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and the other level indicator is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). On the Unit 1 license renewal boundary drawing LR-205216, sheet 1, location D/E-7, the first set of piping lines (2-inch-1CH1143 and 2-inch-1CH1142) for level indicator LA4156/LC4156 are shown correctly as green and within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). However, the Unit 1 license renewal boundary drawing LR-205216, sheet 1, location D/E-6, incorrectly shows the second set of piping lines for level indicator LL6229 as green and within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The drawing is revised to show the piping lines (2-inch-1CH1150, 2-inch-1CH1151, and ¼ inch-1CH1156) and components on the downstream side of the root valves to the No. 1 chilled water expansion tank level indicator LL6229 as red and within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction because the piping contains water and is located in the auxiliary building inner penetration area, which contains safety-related components. Therefore, the piping and components beyond the root valves to the chilled water expansion tank level indicator LL6229 should show as red and within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction.

The Unit 1 piping lines (2-inch-1CH1149 and 2-inch-1CH1148), location D/E-6, up to and including the root valves (valve numbers 1CH153 and 1CH154) for the No. 1 chilled water expansion tank level indicator (LL6229), provide a pressure boundary for the safety-related chilled water system and are within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and are shown correctly as green on this license renewal boundary drawing.

The Unit 2 license renewal boundary drawing LR-205216, sheet 2, location D/E-3, correctly shows the corresponding piping lines (2-inch-2CH1105 and 2-inch-2CH1107) and components for the No. 2 chiller expansion tank level indicators and are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-03 acceptable because the applicant identified and corrected the scoping classification of the piping lines. The staff agrees with the applicant's classification of the Unit 2 piping lines and components for the No. 2 chiller expansion tank level indicators and the Unit 1 piping and components on the downstream side of the root valves to the No. 1 chilled water expansion tank level indicator LL6229 as within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) because of the potential spatial interaction with safety-related components. The staff also agrees with the applicant's classification of Unit 1, location D/E-7, the first set of piping lines for level indicator LA4156/LC4156 and the piping lines for location D/E-6, up to and including the root valves for the No. 1 chilled water expansion tank level indicator because they provide a pressure boundary for the safety-related chilled water system and are within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). Therefore, the staff's concern described in RAI 2.3.3.3-03 is resolved.

2.3.3.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the chilled water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the chilled water system mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.4 Circulating Water System

2.3.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 describes the circulating water system which provides a discharge path to the Delaware River for the service water (SW) system and the non-radioactive liquid waste system. The circulating water system is a normally operating system designed to supply Delaware River water to cool each unit's triple-shell main condenser, discharging the effluent back to the Delaware River at a sufficient distance offshore to minimize thermal recirculation and promote rapid mixing with the river water.

LRA Table 2.3.3-4 identifies the components subject to an AMR for the circulating water system by component type and intended function.

2.3.3.4.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the circulating water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Component Cooling System

2.3.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 describes the component cooling system, which is a normally operating, mechanical system designed to provide heat removal from safeguards equipment associated with heat removal from the RCS during all phases of normal reactor operation. In the event of a LOCA, the system has an ECCS function to reduce RCS temperature through the RHR heat exchangers for long-term core cooling. The heat is then transferred from the component cooling system to the SW system. The component cooling system is also designed to provide intermediate loop cooling for safety-related and nonsafety-related plant loads.

The CC system accomplishes this purpose by circulating chromated cooling water through the safety-related heat exchangers, the ECCS pump mechanical seal coolers, and nonsafety-related plant heat exchangers and coolers.

LRA Table 2.3.3-5 identifies the components subject to an AMR for the component cooling system by component type and intended function.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5, UFSAR Section 9.2.2, and the license renewal boundary drawings using the evaluation methodology described 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 RAIs as discussed below.

In RAI 2.3.3.5-01, dated April 14, 2010, the staff noted that anchors for nonsafety-related piping connected to safety-related piping on 4 drawings (16 locations) could not be located. The staff could not verify that the (a)(2) scoping boundary extended out to the first anchor on the nonsafety line, as described in the applicant's scoping methodology for spatial interaction. Therefore, the staff requested that the applicant provide additional information to locate an anchor on the pipe lines between the safety-nonsafety interface and the end of the (a)(2) scoping boundary.

The applicant's response, dated May 12, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms with the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's response to RAI 2.3.3.5-01 acceptable.

In RAI 2.3.3.5-02, dated April 14, 2010, the staff noted on license renewal drawing LR-205229, sheet 1 a section of pneumatic piping (1063 B-N) within scope for 10 CFR 54.4(a)(2) that continues to license renewal drawing LR-205231, sheet 2 and LR-205315, sheet 1. The continuation on license renewal drawing LR-205231, sheet 2 is not within scope. The applicant was requested to clarify the scoping classification of the pneumatic piping section.

In its response dated May 12, 2010, the applicant stated that the boundary drawing incorrectly shows the pneumatic tubing as within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The pneumatic tubing is not within the scope of license renewal because it does not have the potential for spatial interaction with safety-related components, does not contain high energy fluids, or provide structural support to safety-related components. The pneumatic tubing provides pneumatic supply air to the air-operated valve on the downstream side of the boric acid evaporator condenser. The drawing has been revised to reflect that this pneumatic tubing is not within scope.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.5-02 acceptable because the pneumatic tubing does not contain high energy fluids, does not provide structural support to safety-related components, and does not have the potential for spatial interaction with safety-related components. The staff agrees with the applicant that the pneumatic tubing is not within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.5-02 is resolved.

2.3.3.5.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the CC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.6 Compressed Air System

2.3.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 describes the compressed air system which consists of the following plant systems: the station air system and the control air system. The compressed air system is a normally operating mechanical system that provides motive power for safety-related and nonsafety-related instrumentation, controls, and equipment. The compressed air system also provides compressed air to service air connections throughout the plant, including providing a constant flow of penetration cooling air to hot pipe containment penetrations.

The purpose of the compressed air system is to provide a continuous supply of compressed air at the appropriate pressure, temperature, flow rate, and air quality to support pneumatic instrumentation and controls, air-operated plant and service equipment, and penetration cooling requirements for both Salem units. The compressed air system must supply critical air users with redundant air sources such that the loss of an air header, compressor, or other single failure will not result in the need to shut down the plant or compromise its operation.

LRA Table 2.3.3-6 identifies the components subject to an AMR for the compressed air system by component type and intended function.

2.3.3.6.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the compressed air system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Containment Ventilation System

2.3.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 describes the containment ventilation system which consists of the following plant systems: containment fan cooler system, reactor nozzle support ventilation system, reactor shield ventilation system, pressure–vacuum relief system, containment purge system, hydrogen recombiner system, containment iodine removal system, and control rod drive ventilation system. The containment ventilation system is a normally operating mechanical system designed to provide heat removal from containment during normal operations and DBEs.

The purpose of the containment ventilation system is to provide air circulation and heat removal from the containment atmosphere to prevent overheating. The containment ventilation system accomplishes this purpose by using fans to circulate the containment air through coolers supplied with cooling water by the SW system and to force air through the reactor shield and nozzle support areas. Another purpose of the containment ventilation system is to provide isolation capability to maintain the integrity of the containment barrier. The system accomplishes this purpose by blank flanges or by automatic valves that close when required for containment isolation.

LRA Table 2.3.3-7 identifies the components subject to an AMR for the containment ventilation system by component type and intended function.

2.3.3.7.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the containment ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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).

2.3.3.8 Control Area Ventilation System

2.3.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 describes the control area ventilation system which consists of the following plant systems: the control area air conditioning system and the control room emergency air conditioning system. The control area ventilation system is a normally operating mechanical system designed to maintain room temperatures, humidity, and habitability of the control room envelope and control room areas under normal and DBA conditions.

The purpose of the control area ventilation system is to provide clean, filtered air at satisfactory temperature and humidity to the control room envelope and the control room area and to ensure uninterrupted safe occupancy of the control room envelope under emergency conditions by filtering airborne radioactive particles and maintaining the control room envelope at a positive differential pressure.

LRA Table 2.3.3-8 identifies the components subject to an AMR for the control area ventilation system by component type and intended function.

2.3.3.8.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the control area ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Cranes and Hoists

2.3.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 describes the cranes and hoists system which consists of load handling overhead bridge cranes, monorails, jib cranes, lifting devices, and hoists provided throughout the facility to support operation and maintenance activities. Major cranes include the polar gantry crane, cask-handling crane, main turbine area gantry crane and aux turbine area crane, solid radwaste overhead crane, 90T grove crane, and 900 series American crawler crane. The polar gantry crane services the operating floor and is used to lift heavy loads such as the RV integrated head and upper and lower RV internals.

The purpose of the cranes and hoists system is to safely move material and equipment as required to support operations and maintenance activities.

LRA Table 2.3.3-9 identifies the components subject to an AMR for the cranes and hoists system by component type and intended function.

2.3.3.9.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the cranes and hoists system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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).

2.3.3.10 Demineralized Water System

2.3.3.10.1 Summary of Technical Information in the Application

LRA Section 2.3.3.10 describes the demineralized water system which consists of the following plant systems: the demineralized water makeup system and the demineralized water-restricted areas system. The demineralized water system is a normally operating system designed to purify both well water and recovered water from the condensers to high purity water standards for various uses.

The purpose of the demineralized water system is to provide a source of demineralized water for various vital and non-vital uses, such as providing an alternate supply of demineralized water to the AFW system, providing makeup to the primary water storage tank (PWST), boric acid batching tanks, CC water surge tanks, chilled water expansion tanks, emergency diesel generator (EDG) jacket water expansion tanks, stator cooling, spent fuel pool, and the main condenser. It also provides a source of flushing water to the safety injection, RHR, condensate polisher, and the SGs. Portions of the demineralized water system are also credited for post-fire safe shutdown.

LRA Table 2.3.3-10 identifies the components subject to an AMR for the demineralized water system by component type and intended function.

2.3.3.10.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the demineralized water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.11 Emergency Diesel Generator and Auxiliaries System

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 describes the emergency diesel generator and auxiliaries (EDGA) system. The EDGA system is a standby mechanical system designed to supply electrical power to key plant components when normal offsite power sources are not available.

The purpose of the EDGA system is to provide electrical power for engineered safety features when normal offsite power is not available. Any two of the three diesel generators and their associated vital busses can supply sufficient power for operation of the required safeguards equipment for a design basis LOCA coincident with a loss of offsite power.

LRA Table 2.3.3-11 identifies the components subject to an AMR for the EDGA system by component type and intended function.

2.3.3.11.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the EDGA system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.12 Fire Protection System

2.3.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 describes the fire protection system which consists of the following plant systems: fire protection water systems, carbon dioxide (CO_2) systems, the halon system, the foam system, portable fire extinguishers, and fire detection and alarm systems. The fire protection system also includes fire barriers, penetrations seals, and fire wrap for cable trays. The fire protection system is a normally operating mechanical system designed for the rapid detection and suppression of a fire at the plant.

The purpose of the fire protection system is to: (1) prevent fires from starting; (2) promptly detect and suppress fires to limit damage; and (3) in the event of a fire, allow for safe shutdown of the reactor to occur. The fire protection system accomplishes this purpose by providing fire protection equipment in the form of detectors, alarms, fire barriers, and suppression systems for selected areas of the plant. In addition, the fire protection system provides a backup source of water to the AFW system in the event of loss of the AFW storage tanks. The Salem's fire protection water system is physically connected to the Hope Creek Generating Station fire water system by the use of sectionalizing valves. The two systems are normally isolated from each other.

LRA Table 2.3.3-12 identifies the components subject to an AMR for the fire protection system by component type and intended function.

2.3.3.12.2 Staff Evaluation

The staff reviewed the LRA; license renewal drawings; UFSAR Section 9.5.1.1, "Fire Protection Program"; and the following fire protection CLB documents listed in Salem Unit 1, Operating License Condition 2.C(5) and in Salem Unit 2, Operating License Condition 2.C(10): Amendment No. 21 to Facility Operating License No. DPR-70, dated November 20, 1979, and safety evaluation reports dated September 16, 1982, November 5, 1982, June 17, 1983, July 20, 1989, November 14, 1990, June 17, 1994, and January 7, 2004.

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 in accordance with 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 of LRA Section 2.3.3.12 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3.3.12-1 of its letter dated March 22, 2010, the staff stated that license renewal drawing LR-205221, sheet 1 showed the following fire protection system components as out of scope (i.e., not colored in green): production wells Nos. 1, 2, 3, 5, and 6 in the fresh water well pump house; fire pump house; and tank 1FWE4 and associated components to the fire pump house and to the fire protection storage tank 1FWE16.

The staff requested that the applicant verify whether the fire protection systems and components listed above are within 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), or provide justification for the exclusion if these systems and components are not subject to an AMR.

In a letter dated April 19, 2010, the applicant responded to RAI 2.3.3.12-1 and stated:

> License renewal drawing LR-205222, Sheet 4, "Fire Protection," shows the No. 1 and No. 2 fresh water and fire protection water storage tanks. Each tank has a capacity of 350,000 gallons, with 300,000 gallons reserved for fire protection use and 50,000 gallons available for domestic service. The reserved capacity in each tank is sufficient to supply the greatest system demand plus an additional 1000 [gallons per minute] GPM for hose streams for a minimum of two hours, representing 100 percent redundant capacity. These two independent tanks supply water to the two fire pumps (1FPE12, 2FPE12) and jockey pump (1FPE11). The fire pump suction piping and valve arrangement allows either fire pump to take water from either or both water storage tanks.
>
> The fresh water and fire protection water storage tanks are also shown on license renewal drawing LR-205221, Sheet 1, "Fresh Water." The fresh water system uses the 50,000 gallons available in each tank that is not reserved for fire protection. The production wells (Nos. 1, 2, 3, 5, and 6) in the fresh water well pump house are included in the fresh water system as described in LRA Section 2.3.3.13, and are not part of the fire protection system. Similarly, the 15,000 gallon fresh water tank (1FWE4), fresh water pumps, pressure booster pumps, fresh water supply chlorination tank and associated piping and components up to, but not including the fresh water and fire protection water storage tanks 1FWE16 and 1FWE18, are part of the fresh water system.
>
> The fresh water system is a nonsafety-related, normally operating mechanical system designed to provide a source of water for potable, sanitary, and process make-up use. The system also provides makeup water from the production wells to the fresh water and fire protection water storage tanks, which are part of the fire protection system. Water level in each tank is maintained above the minimum required to assure a reserve volume of 300,000 gallons for fire protection. The reserve volume in each tank is adequate to meet fire protection system demands in the event of a fire, without the need for tank makeup. The fresh water system production well pumps and associated piping and components are not required to support any fire protection intended functions for license renewal.

> The fresh water system piping and components shown in black on drawing LR-205221, Sheet 1 do not provide structural support for safety-related components, and do not have the potential for spatial interaction because they are not located in the vicinity of safety-related components. Therefore, the production wells (Nos. 1, 2, 3, 5, and 6) in the fresh water well pump house, the 15,000 gallon fresh water tank (1FWE4), and the associated piping and components in the fresh water system shown in black on drawing LR-205221, Sheet 1 are not within the scope of license renewal and are not subject to AMR.
>
> The fire pump house structure is within the scope of license renewal, and is addressed in the LRA Sections 2.4.4 and 2.4.17 for structures.

The staff reviewed the applicant's response to RAI 2.3.3.12-1. The staff verified that production wells Nos. 1, 2, 3, 5, and 6 and tank 1FWE4 and associated components to the fire pump house and to the fire protection storage tank 1FWE16 are part of the fresh water system. Further, the staff found that, since the fresh water system does not have any intended functions that satisfy any of the criteria in 10 CFR 54.4(a), the fresh water system and its components (e.g., production wells Nos. 1, 2, 3, 5, and 6 and tank 1FWE4 and associated components to the fire pump house and to the fire protection storage tank 1FWE16) are not within the scope of license renewal and are not subject to an AMR. Based on its review, the staff finds the applicant's response to this portion of RAI 2.3.3.12-1 acceptable for the purpose of determining whether the applicant has adequately identified the fire protection system components within the scope of license renewal.

The staff also reviewed the applicant's response to RAI 2.3.3.12-1 in regard to the fire pump house. The staff verified that the fire pump house is within the scope of license renewal as stated in LRA Sections 2.4.4 and 2.4.17. Based on its review, the staff finds the applicant's response to RAI 2.3.3.12-1 in regard to the fire pump house acceptable for the purpose of determining whether the applicant has adequately identified the fire protection system components within the scope of license renewal.

In RAI 2.3.3.12-2 of its letter dated March 22, 2010, the staff stated that LRA Tables 2.3.3-12 and 3.3.2-12 do not include the following fire protection components: hose racks, filter housing, flame arrestor, passive components in diesel engines for fire water pumps, fire retardant coating for structural steel, and fire retardant coating on duct work.

The staff requested that the applicant verify whether the fire protection components listed above are within 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). The staff further requested that, if these components are excluded from the scope of license renewal and are not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 19, 2010, the applicant responded to RAI 2.3.3.12-2 and stated:

> The scoping results of each of the fire protection components are as follows:
>
> <u>Hose Racks</u>: Hose rack assemblies consist of valves, piping and fittings. These components are in the scope of license renewal and subject to AMR. They are included in the "Valve Body" and "Piping and Fittings" component types in LRA Tables 2.3.3-12 and 3.3.2-12. Fire hoses associated with hose racks are evaluated as consumables as described in LRA Section 2.1.6.4. Fire hoses are

periodically inspected in accordance with [National Fire Protection Association] NFPA standards and replaced as required. Therefore, fire hoses are not considered long-lived and are not subject to an AMR.

Filter Housing: Filter housings are included in the component category of Strainer Body in LRA Tables 2.3.3-12 and 3.3.2-12 and, therefore, are within the scope of license renewal and are subject to an AMR.

Flame Arrestor: Flame arrestors exist on each of the six Diesel Fuel Oil Day Tanks and on each of the two Fire Pump Day Tanks. They are shown on Boundary Drawings 205249, Sheets 2 and 3. These flame arrestors are evaluated with the fuel oil system. LRA Tables 2.3.3-16 and 3.3.2-16 include flame arrestors as a component type. Therefore, flame arrestors are within the scope of license renewal and are subject to an AMR.

Passive components in diesel engines for fire water pumps: The diesel-driven fire water pumps were purchased as a pump and pump driver assembly from the pump manufacturer. The pump and diesel engine driver are mounted together on the vendor-supplied equipment base plate, which is anchored and grouted to the fire pump house foundation slab. The equipment supports and supporting structural components are subject to an AMR and are included in the applicable tables in LRA Sections 2.4.4 and 3.5.

The diesel engines as supplied from the manufacturer include various components necessary to support engine operation. Many of these components are either internal to the engine, or are physically mounted on the engine. These components are considered integral subcomponent parts of the active diesel engine assembly. Table 2.1-5 of NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" and Appendix B of NEI 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule" indicate that Fire Pump Diesel Engines are not subject to an AMR. The engine components that are part of the active engine assembly are not included in LRA Tables 2.3.3-12 or 3.3.2-12. LR-205249 boundary drawing, Sheet 3, Note 7 indicates that the diesel engine is an active assembly and not subject to an AMR.

Fuel oil components that are not part of the active diesel engine assembly are evaluated with the fuel oil system and are included in LRA Tables 2.3.3-16 and 3.3.2-16. This includes the fuel oil storage tank and the fuel inlet and return piping and components from the tank up to the diesel engine assembly. The component types are Tanks, Piping and Fittings, and Valve Body.

Fire retardant coating for structural steel: There is no fire retardant coating on structural steel at Salem. Therefore, this coating is not included in Tables 2.3.3-12 and 3.3.2-12. Fire retardant coating is not in the scope of license renewal and is not subject to AMR.

Fire retardant coating on duct work: Fire retardant coating on duct work is included in the component category Fire Barriers (Wraps) in LRA Tables 2.3.3-12 and 3.3.2-12 and is within the scope of license renewal and is subject to an AMR.

The staff reviewed the applicant's response to RAI 2.3.3.12-2. The staff verified that the following components are addressed in the LRA, that they are within the scope of license renewal, and subject to an AMR: hose racks are addressed under the component categories of valve body/piping and fittings in LRA Tables 2.3.3-12 and 3.3.2-12; filter housings are addressed under the component category strainer body in LRA Tables 2.3.3-12 and 3.3.2-12; flame arrestors are addressed as part of the fuel oil system in LRA Tables 2.3.3-16 and 3.3.2-16; and fire retardant coating on duct work is addressed under the component category fire barriers in LRA Tables 2.3.3-12 and 3.3.2-12. Based on its review, the staff concludes that hose racks, filter housings, flame arrestors, and fire retardant coating on duct work are included within the scope of license renewal and are subject to an AMR. The staff found the applicant's response to this portion of RAI 2.3.3.12-2 acceptable.

The staff also reviewed the applicant's response to RAI 2.3.3.12-2 in regard to passive components in diesel engines for fire water pumps. The applicant stated that the passive components in diesel engines for fire water pumps are evaluated with the fuel oil system in LRA Tables 2.3.3-16 and 3.3.2-16 under the passive component types of tanks, piping and fittings, and valve body. These passive components include the fuel oil storage tank, the fuel inlet, and return piping and components from the tank up to the diesel engine assembly. The staff reviewed the applicant's response and verified that the passive components in diesel engines for fire water pumps listed by the applicant are included in LRA Tables 2.3.3-16 and 3.3.2-16, that they are included within the scope of license renewal, and are subject to an AMR. The staff found the applicant's response to this portion of RAI 2.3.3.12-2 acceptable. The staff agrees with the applicant that the active components that are part of the diesel engine assembly are not within the scope of license renewal and are not subject to an AMR. Based on its review, the staff found the applicant's response to this portion of RAI 2.3.3.12-2 acceptable.

Finally, in regard to fire retardant coating on structural steel, the applicant stated that there is no fire retardant coating on structural steel at Salem and that, therefore, fire retardant coating on structural steel is not included in LRA Tables 2.3.3-12 and 3.3.2-12. Based on the applicant's statement that there is no fire retardant coating on structural steel, the staff found the applicant's response to this portion of RAI 2.3.3.12-2 acceptable.

Based on its review, the staff found that the applicant had addressed and resolved each item in response to RAI 2.3.3.12-2 as discussed above. Therefore, the staff found the applicant's response to RAI 2.3.3.12-2 acceptable for the purpose of determining whether the applicant has adequately identified the fire protection system components within the scope of license renewal.

In RAI 2.3.3.12-3 of its letter dated March 22, 2010, the staff quoted Sections 4.0 and 5.0 of the SER dated June 17, 1983. Section 4.0 states that fire protection in fire zone P1E elevation 84 feet auxiliary building electrical penetration area is provided, in part, by a manually operated total flooding CO_2 extinguishing system and Section 5.0 states that fire protection in fire area P1B 4-kilovolt (kV) switchgear room is provided, in part, by a manually operated CO_2 extinguishing system.

The staff requested that the applicant verify whether the CO_2 fire suppression systems listed above are within 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). The staff further requested that, if these systems are not within the scope of license renewal and are not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 19, 2010, the applicant responded to RAI 2.3.3.12-3 and stated:

> A plant modification was completed in 2008 that replaced CO_2 fire suppression systems located in the Auxiliary Building Penetration Areas and in the 4 kV Switchgear Rooms with closed head dry pipe pre-action type sprinkler systems. These sprinkler systems serve the Auxiliary Building Electrical Penetration Areas at elevation 78', the 4 kV Switchgear Rooms at elevation 64', and also the 460 Volt Switchgear Rooms at elevation 84' for Salem Units 1 and 2.
>
> The sprinkler systems are in the scope of license renewal and are subject to AMR. The Salem Unit 1 sprinkler systems are shown on drawing LR-205222, sheet 1 at H-3 and H-4. The Salem Unit 2 sprinkler systems are shown on drawing LR-205222, sheet 2 at B-2 and B-3. These systems are designated as green on the drawings indicating that they are within the scope of license renewal and are subject to an AMR.

The staff reviewed the applicant's response to RAI 2.3.3.12-3. The applicant stated that the CO_2 fire suppression systems located in the auxiliary building penetration areas and in the 4-kV switchgear rooms were replaced by closed head dry pipe pre-action type sprinkler systems. Given the fact that these CO_2 fire suppression systems are no longer in use, the staff finds the applicant's 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.

In RAI 2.3.3.12-4 of its letter dated March 22, 2010, the staff quoted Sections 1.3 and 6.2 of the SER dated July 20, 1989. Section 1.3 states that, "Where non-rated hatches exist, either the area below is protected by an automatic fire suppression system or potential fire spread up through the hatch will not affect redundant shutdown systems…" and Section 6.2 states that, "...the licensee proposed to implement the following modifications: Expand the existing wet-piping sprinkler system in the charging pump area to provide full coverage around the pump…"

The staff requested that the applicant verify whether the fire protection suppression systems listed above are within 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). The staff further requested that, if these fire suppression systems are not within the scope of license renewal and not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 19, 2010, the applicant responded to RAI 2.3.3.12-4 and stated:

> Automatic fire suppression systems do not exist in areas below non-rated steel hatches at Salem Unit 1 and Unit 2. Engineering evaluation of the non-rated steel hatch configurations has determined that, under credible fire scenarios, and with proper control of combustible loading, fires will not spread up through hatches and affect redundant shutdown equipment. Plant areas near the subject hatch locations have been designated as combustible control zones for controlling the plant configuration relative to maintenance of low combustible loads. Implementation of these combustible control zones ensures the integrity of the non-rated steel hatches during a fire and eliminates the need for automatic fire suppression systems in areas below the hatches.

> The expanded wet-piping sprinkler systems in the charging pump area and the enhanced sprinkler systems that protect the auxiliary feedwater pumps are in the scope of license renewal and are subject to an AMR. These systems are designated as green on drawings LR-205222, Sheet 1 at F-4, C-4 (charging pump area) and Sheet 2 at D-6, D-8 (auxiliary feedwater pumps).

The staff reviewed the applicant's response to RAI 2.3.3.12-4. Based on the applicant's statement that there are no automatic fire suppression systems below the non-rated hatches, the staff finds the applicant's response to this portion of RAI 2.3.3.12-4 acceptable.

In regard to the wet-pipe sprinkler system in the charging pump area and the sprinkler systems that protect the AFW pumps, the applicant stated that these fire protection suppression systems are within the scope of license renewal and subject to an AMR. Based on its review, the staff finds the applicant's response to this portion of RAI 2.3.3.12-4 acceptable.

Based on its review, the staff found that the applicant had addressed and resolved each item in response to RAI as discussed above. Therefore, the staff found the applicant's response to RAI 2.3.3.12-4 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

The staff reviewed the LRA, UFSAR, RAI responses, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the fire protection system and components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the fire protection system and components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 Fresh Water System

2.3.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the fresh water system, which is a normally operating mechanical system designed to provide the plants with a source of water for potable, sanitary, fire protection, or process makeup use. The fresh water system has interfaces with the following systems and components: the chilled water system, the demineralized water system, the fire protection system, the heating water and heating steam system, the main condensate and feedwater (MCFW) system, the main condenser and air removal (MCAR) system, the main steam (MS) system, the main turbine and auxiliaries (MTA) system, the non-radioactive drain system, the non-radioactive liquid waste system, and the SGs.

The purpose of the fresh water system is to provide the plants with a source of raw water for non-potable use, or for further treatment for potable or plant use. The fresh water system accomplishes this purpose via production wells, pumps, heat exchangers, tanks, piping, piping components, and plumbing fixtures.

LRA Table 2.3.3-13 identifies the components subject to an AMR for the fresh water system by component type and intended function.

2.3.3.13.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fresh water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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).

2.3.3.14 Fuel Handling and Fuel Storage System

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the fuel handling and fuel storage system which consists of the following plant systems: the fuel handling system and the fuel handling tools system. The fuel handling and fuel storage system is a mechanical system designed to manipulate and store new and spent fuel and control fuel geometry when the fuel is not in the core.

The purpose of the fuel handling and fuel storage system is to provide a safe, effective means of storing, transporting, and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. The fuel handling and fuel storage system controls fuel storage positions to: (1) assure a geometrically safe configuration with respect to criticality, (2) ensure adequate shielding of irradiated fuel for plant personnel to accomplish normal operations, (3) prevent mechanical damage to the stored fuel that could result in significant release of radioactivity from the fuel, and (4) provide means for the safe handling of new and irradiated fuel.

LRA Table 2.3.3-14 identifies the components subject to an AMR for the fuel handling and fuel storage system by component type and intended function.

2.3.3.14.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fuel handling and fuel storage system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Fuel Handling Ventilation System

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 describes the fuel handling ventilation system which consists of the fuel handling ventilation supply system, the fuel handling ventilation exhaust system, and ventilation systems for the store room and vent sampling room. The fuel handling ventilation system is a normally operating mechanical system designed to maintain the fuel handling building at a slight negative pressure with respect to atmosphere to prevent uncontrolled release of radioactive material from the fuel handling building. The fuel handling ventilation system also serves to: (1) maintain the fuel handling building within the design temperature limits during fuel handling activities, (2) route air from the spent fuel pool and high contamination areas to the filter unit before releasing it to the atmosphere, (3) direct air flow from cleaner or less contaminated areas to areas of higher contamination, and (4) provide ventilation for the storeroom and vent sampling enclosure.

The purpose of the fuel handling ventilation system is to maintain the fuel handling building at a slight negative pressure with respect to atmosphere to assure inleakage of air rather than outleakage. The system accomplishes this purpose by using two fans and two filter trains to exhaust air from the fuel handling building.

LRA Table 2.3.3-15 identifies the components subject to an AMR for the fuel handling ventilation system by component type and intended function.

2.3.3.15.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fuel handling ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Fuel Oil System

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 describes the fuel oil system, which is a normally operating mechanical system designed to receive, store, and condition fuel oil for eventual transfer.

The purpose of the fuel oil system is to transfer fuel oil to the following systems and equipment: the gas turbine (Unit 3), house heating boilers, the technical support center EDG, the EDGA system, the fire protection system, the circulating water intake heating boiler, and the SW intake hot air furnace. The fuel oil system accomplishes this purpose by providing pumps, filters and associated piping, and components necessary to unload, filter, and transfer fuel oil.

LRA Table 2.3.3-16 identifies the components subject to an AMR for the fuel oil system by component type and intended function.

2.3.3.16.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fuel oil system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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).

2.3.3.17 Heating Water and Heating Steam System

2.3.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 describes the heating water and heating steam system which consists of the following systems: the house heating boiler and heating water/heating steam (heating boilers). The heating water and heating steam system is a normally operating mechanical system designed to provide the site with a source of hot water to maintain area and equipment temperatures within normal limits and steam to support process heaters.

The purpose of the heating water and heating steam system is to provide the site with a source of hot water and steam to maintain area, equipment, and process temperatures within normal limits. The system accomplishes this purpose by using either bleed steam from one of the operating unit turbines or from the oil fired-heating boilers to supply steam to: (1) process heaters; (2) heat water that is circulated by pumps, piping, and associated controls; and (3) heat exchangers and area heaters to maintain tank content and area temperatures.

LRA Table 2.3.3-17 identifies the components subject to an AMR for the heating water and heating steam system by component type and intended function.

2.3.3.17.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the heating water and heating steam system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Non-radioactive Drain System

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 describes the non-radioactive drain system, which is a normally operating mechanical system designed to provide non-contaminated drainage control and management for the Salem site.

The purpose of the non-radioactive drain system is to collect, forward, and as required, treat miscellaneous drainage from buildings, equipment, and yard areas for drainage to be discharged to the Delaware River in compliance with the New Jersey Pollutant Discharge Elimination System (NJPDES) permit. The non-radioactive drain system accomplishes this purpose by providing drains, drain flowpaths, sumps, sump pumps, and discharge flowpaths from buildings and yard areas, and as required, by treating these drains via the oil-water separator, or by the non-radioactive liquid waste system prior to discharge to the Delaware River.

LRA Table 2.3.3-18 identifies the components subject to an AMR for the non-radioactive drain system by component type and intended function.

2.3.3.18.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the non-radioactive drain system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and 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 Radiation Monitoring System

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 describes the radiation monitoring (RM) system. The purpose of the RM system is to detect, compute, indicate, annunciate, and record radiation levels at selected locations inside the plant. The RM system accomplishes this purpose by providing process, process filter, and area radiation monitors. It also provides interlock signals to support intended functions on high radiation level detection.

LRA Table 2.3.3-19 identifies the components subject to an AMR for the RM system by component type and intended function.

2.3.3.19.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RM system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.20 Radioactive Drain System

2.3.3.20.1 Summary of Technical Information in the Application

LRA Section 2.3.3.20 describes the radioactive drain system, which is a normally operating mechanical system designed to provide: (1) contaminated drainage control and management for the auxiliary building, containment structure, penetration areas, and the FHB; (2) flood protection for equipment in the auxiliary and FHBs; and (3) flowpaths from various safety-relief valves to the radwaste system.

The purpose of the radioactive drain system is to collect and forward miscellaneous drainage from buildings and equipment, and safety-relief valve discharges to the radwaste system. The system accomplishes this purpose by providing drains, drain flowpaths, pumps, and discharge flowpaths from buildings and equipment, including safety-relief valve discharges, to the radwaste system.

LRA Table 2.3.3-20 identifies the components subject to an AMR for the radioactive drain system by component type and intended function.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20; UFSAR Sections 3.4.3.1, 6.3.5.4, and 9.3.3; and the license renewal boundary drawings using the evaluation methodology described 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 RAIs as discussed below.

In RAI 2.3.3.20-01, dated April 14, 2010, the staff noted license renewal drawing LR-205227, sheet 3 shows the RCP oil lift pumps within scope for 10 CFR 54.4(a)(1) or (a)(3). However, the connected oil and water separators and piping to trench 1WDE17 are not within scope. License renewal drawing LR-205327, sheet 3 does not show the RCP oil collection system, water separators, and associated piping and components as within scope. The applicant was requested to provide additional information to clarify why these nonsafety-related piping and components that contain water and oil, and that are located inside structures that contain safety-related SSCs, are not included within scope for potential spatial interaction in accordance with 10 CFR 54.4(a)(2).

In its response dated May 12, 2010, the applicant stated the boundary drawings were incorrectly shown. The Unit 1 RCP oil lift pumps' oil and water separators and piping leading to trench 1WDE17 have been included as within the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The Unit 2 RCP oil lift pumps' oil collection system to trench 2WDE17 have also been included within the scope of license renewal in accordance with 10 CFR 54.4(a)(3). LRA Table 2.3.3-12 was revised to include a component type "tanks" (i.e., the oil and water separators). The applicant further revised the intended function of the tanks (reactor coolant pump oil collection enclosure and oil and water separator) from "Leakage Boundary" to "Pressure Boundary."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-01 acceptable because the components in question up to the trenches have been included within scope. Therefore, the staff's concern described in RAI 2.3.3.20-01 is resolved.

In RAI 2.3.3.20-02, dated April 14, 2010, the staff noted four instances of piping within scope drawing continuations to piping not within scope on the continuation drawing. The applicant was requested to clarify the scoping classification for these pipe sections.

In its response dated May 12, 2010, the applicant stated that the four instances resulted from two lines for which the highlighting was incorrectly reversed. The applicant stated the drawings have been corrected to show the continued piping as within scope for 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-02 acceptable because the applicant explained that the highlighting of the lines in question had been reversed and the drawings have been corrected. Therefore, the staff's concern described in RAI 2.3.3.20-02 is resolved.

In RAI 2.3.3.20-03, dated April 14, 2010, the staff noted two instances of 10 CFR 54.4(a)(1) or (a)(3) piping continued as 10 CFR 54.4(a)(2) piping on the continuation drawing. The applicant was requested to clarify the scoping classification for these pipe sections.

In its response dated May 12, 2010, the applicant stated the drain lines from the PWST are shown incorrectly as within scope for 10 CFR 54.4(a)(1) or (a)(3). The applicant stated that the drawing has been revised to show these drain lines as within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) up to the drain header.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-03 acceptable because the applicant described the scoping changes and indicated the drawings had been corrected. Therefore, the staff's concern described in RAI 2.3.3.20-03 is resolved.

2.3.3.20.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the radioactive drain system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the radioactive drain components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.21 Radwaste System

2.3.3.21.1 Summary of Technical Information in the Application

LRA Section 2.3.3.21 describes the radwaste system which consists of the following plant systems associated with the processing of radioactive waste products: the boron recovery system, the waste liquid (radioactive) system, the waste gas (radioactive) system, and the waste solid (radioactive) system. The radwaste system is a normally operating mechanical system designed to provide the equipment necessary to collect, process, and prepare radioactive liquid, gaseous, and solid wastes for disposal.

The primary purpose of the radwaste system is to manage the collection and processing of the liquid waste and gaseous waste from the RCS. The radwaste system accomplishes this purpose with a variety of tanks, piping, and piping components.

LRA Table 2.3.3-21 identifies the components subject to an AMR for the radwaste system by component type and intended function.

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.21; UFSAR Sections 11.2, 11.3, 11.5, and 9.3.4.2; and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.21-01, dated April 14, 2010, the staff noted two instances of within scope pneumatic tubing continuing to other drawings where the continuations were not within scope. The applicant was requested to clarify the scoping classification for these pneumatic tubing sections.

In its response dated May 12, 2010, the applicant stated that in both instances the boundary drawing incorrectly shows the pneumatic tubing as within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The pneumatic tubing is not within the scope of license renewal because it does not have the potential for spatial interaction since it does not contain fluids and does not provide structural support to safety-related components. The drawing has been revised to reflect that this pneumatic tubing is not within scope.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.21-01 acceptable because the applicant clarified that this pneumatic tubing was incorrectly shown as within scope. Therefore, the staff's concern described in RAI 2.3.3.21-01 is resolved.

2.3.3.21.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the radwaste system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the radwaste mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.22 Sampling System

2.3.3.22.1 Summary of Technical Information in the Application

LRA Section 2.3.3.22 describes the sampling system which consists of the following plant systems: the sampling system and the post-accident sampling system (PASS). Salem Units 1 and 2 no longer operate the PASS because it was removed from the CLB, and it was physically drained and disconnected from the plant. The major components of the sampling system are heat exchangers, piping, valves, and piping components. The sampling system is a normally operating mechanical system designed to obtain liquid and gas samples for laboratory analyses of chemistry and radiochemistry conditions of the reactor coolant, RHR, chemical and volume control, safety injection, DW, MCFW, MS, and SGs systems. Samples can be provided under operating conditions from full power to cold shutdown.

The purpose of the sampling system is to provide liquid and gas samples from various locations in the plant to designated locations, including online analytical equipment and grab samples for analysis, for purposes of guidance in operation of the reactor coolant, RHR, CC, chemical and volume control, MS, safety injection, and SGs systems. The sampling system also provides containment isolation.

LRA Table 2.3.3-22 identifies the components subject to an AMR for the sampling system by component type and intended function.

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22, UFSAR Sections 9.3.2 and 9.3.6, and the license renewal boundary drawings using the evaluation methodology described 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.

In RAI 2.3.3.22-01, dated April 14, 2010, the staff noted on license renewal drawings LR-205244, sheet 1 and LR-205344, sheet 1, 3/8-inch lines as within scope for 10 CFR 54.4(a)(2) and connected at three-way valves with a ½-inch O.D. tubing which is shown as not within scope. In both cases, two lines exiting the three-way valve are within scope for 10 CFR 54.4(a)(2), while the third is not. The applicant was requested to provide additional information to clarify the scoping classification of this pipe section.

In its response dated May 12, 2010, the applicant stated line 6714 Y-N on license renewal drawing LR-205244, sheet 1 was previously used to conduct samples from the Nos. 11 and 12 RHR heat exchanger outlets to the Salem Unit 1 PASS. The PASS has been abandoned in place, and the port of the three-way valve connected to line 6714 Y-N is kept in a closed position to provide isolation from the PASS equipment. The Salem Unit 2 PASS has also been abandoned in place, so the same case exists for license renewal drawing LR-205344, sheet 1. Neither line contains water, steam, or oil and does not provide structural support to safety-related components. Therefore, the lines are correctly shown as not within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-01 acceptable because the applicant clarified the scoping classification of the pipe in question. Therefore, the staff's concern described in RAI 2.3.3.22-01 is resolved.

2.3.3.22.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the sampling system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the sampling system mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.23 Service Water System

2.3.3.23.1 Summary of Technical Information in the Application

LRA Section 2.3.3.23 describes the SW system, which is a normally operating auxiliary system designed to provide cooling water from the Delaware River to safety-related and nonsafety-related plant components.

The purpose of the SW system is to circulate cooling water from the river through both safety-related and nonsafety-related heat exchangers and back to the river. The SW system consists of three parallel loops: two nuclear headers and one non-nuclear header. The SW system accomplishes this purpose by providing screened river water to the SW pump suctions and then circulating river water through each nuclear header which includes a CC heat exchanger, lube oil and gear oil coolers for the ECCS pumps, ECCS pump room coolers, diesel generator heat exchangers, containment fan coil units, and chiller condensers. Additionally, SW can provide cooling for the emergency air compressor, when it is aligned manually in the field.

There are also two SW accumulators (one for each nuclear header), which maintain the containment fan coil unit piping filled in the containment during the diesel generator sequencing following a DBE.

LRA Table 2.3.3-23 identifies the components subject to an AMR for the SW system by component type and intended function.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.23, UFSAR Section 9.2.1, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3.3.23-01, dated April 14, 2010, the staff noted on license renewal drawing LR-205212, sheet 1 a section of 10 CFR 54.4(a)(1) 6-inch SW line that continues to license renewal drawing LR-205309, sheet 3, where the same line continuation is 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 May 12, 2010, the applicant stated that the continuation of the 6-inch SW line was incorrectly shown as not within scope on the drawing and that this line should be within scope for 10 CFR 54.4(a)(2) for functional support. The applicant stated the drawing has been revised to show the 6-inch line as within the scope of license renewal up to the circulating water river discharge header and including all the components in between. This revision did not result in identifying any new component types subject to an AMR. The applicant also revised the third system intended function for clarity.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.23-01 acceptable because the applicant corrected the scoping classification of the pipe line in question. Therefore, the staff's concern described in RAI 2.3.3.23-01 is resolved.

In RAI 2.3.3.23-02, dated April 14, 2010, the staff noted on Unit 1 license renewal drawing LR-205239, sheet 1, 2-inch-1SW1460 as within scope for 10 CFR 54.4(a)(1). Connected to 2-inch-1SW1460 are 10 CFR 54.4(a)(2) 2-inch-1295, 2-inch-1292, 2-inch-1293, and ¾-inch-1291 lines. On Unit 2 license renewal drawing LR-205339, sheet 1, 2-inch-1053 is within scope for 10 CFR 54.4(a)(1). Connected to 2-inch-1053 are 10 CFR 54.4(a)(2) 2-inch-1WL1295, 2-inch-1074, and ¾-inch-1318 lines. The 10 CFR 54.4(a)(2) scoping boundary ends before these lines reach the waste monitor tanks or pumps. No anchor point was identified between the end of the 10 CFR 54.4(a)(2) scoping boundary and the safety-nonsafety interface. The applicant was requested to provide additional information to locate the seismic anchors or anchored components between the ends of the 10 CFR 54.4(a)(2) scoping boundary and the safety-nonsafety interfaces.

The applicant's response, dated May 12, 2010, described the location of the seismic anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's response to RAI 2.3.3.23-02 acceptable.

In RAI 2.3.3.23-03, dated April 14, 2010, the staff noted on Unit 1 license renewal drawing LR-205242, sheet 1 a continuation (1-inch S.L.) from license renewal drawing LR-205209, sheet 4 as within the scope for 10 CFR 54.4(a)(2). This line is connected to a 3-inch SW line within scope for 10 CFR 54.4(a)(1). On Unit 2 license renewal drawing LR-205342, sheet 1, a continuation (1 inch S.L.) from license renewal drawing LR-205209, sheet 4 is within scope for 10 CFR 54.4(a)(2). This line is connected to a 1-inch SW line within scope for 10 CFR 54.4(a)(1). The seismic anchor or anchored component for the two 10 CFR 54.4(a)(2) 1-inch lines could not be located. The applicant was requested to provide additional information to locate the seismic anchors or anchored components between the ends of the 10 CFR 54.4(a)(2) scoping boundary and the safety-nonsafety interface.

In its response dated May 12, 2010, the applicant described the location of the seismic anchors, which are within the existing (a)(2) scoping boundary. This conforms with the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's response to RAI 2.3.3.23-03 acceptable.

In RAI 2.3.3.23-04, dated April 14, 2010, the staff noted on license renewal drawing LR-205242, sheet 3 a ¾-inch 10 CFR 54.4(a)(1) line connected to a 10 CFR 54.4(a)(2) line (7003 Y-N). The seismic anchor or anchored component for the 10 CFR 54.4(a)(2) line could not be located. The applicant was requested to provide additional information to locate the seismic anchor or anchored component between the end of the 10 CFR 54.4(a)(2) scoping boundary and the safety-nonsafety interface.

In its response dated May 12, 2010, the applicant stated that the tubing beyond the safety-nonsafety interface is non-seismic and provided the location of the seismic anchor for the 10 CFR 54.4(a)(1) line.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.23-04 acceptable because the applicant clarified that the tubing was non-seismic and provided the location for the 10 CFR 50.54(a)(1) seismic anchor. Therefore, the staff's concern described in RAI 2.3.3.23-04 is resolved.

2.3.3.23.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and boundary drawings to determine whether the applicant had failed to identify any components within the scope of license renewal. In addition, the staff's review determined that the applicant had not failed to identify any components that should be subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the SW system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the SW system mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.24 Service Water Ventilation System

2.3.3.24.1 Summary of Technical Information in the Application

LRA Section 2.3.3.24 describes the SW ventilation system which consists of four SW intake compartments. The SW ventilation system for each compartment consists of an outside air intake penthouse, power-operated intake and exhaust dampers, and two exhaust fans discharging to the outdoors. The SW ventilation system is a normally operating system designed to remove waste heat from the SW system components located in the SW intake structure.

The purpose of the SW ventilation system is to remove waste heat from the SW system components located in the SW intake structure. The system accomplishes this purpose by exhausting air from the SW intake structure SW intake compartments and control rooms.

LRA Table 2.3.3-24 identifies the components subject to an AMR for the SW ventilation system by component type and intended function.

2.3.3.24.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the SW ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the SW ventilation system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.25 Spent Fuel Cooling System

2.3.3.25.1 Summary of Technical Information in the Application

LRA Section 2.3.3.25 describes the spent fuel cooling (SFC) system. The SFC system is a normally operating mechanical system designed to remove from the spent fuel pool the heat generated by stored spent fuel elements. The SFC system consists of the following three loops: the pool cooling loop, the purification loop, and the skimmer loop.

The purpose of the SFC system is to maintain spent fuel pool temperatures within design limits. The purpose of the pool cooling loop is to remove decay heat from the spent fuel stored in the spent fuel pool. The purpose of the purification loop is to purify water from the spent fuel pool, transfer pool, and RWST. The purpose of the skimmer loop is to maintain clarity of the spent fuel pool water by removing particles floating on the surface of the pool water.

LRA Table 2.3.3-25 identifies the components subject to an AMR for the SFC system by component type and intended function.

2.3.3.25.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25, UFSAR Section 9.1.3, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.25-01, dated April 14, 2010, the staff noted on license renewal drawing LR-205333, sheet 1 two instances of anchors for nonsafety-related piping connected to safety-related piping that could not be located. The applicant was requested to provide additional information to locate the seismic anchors or anchored components between the ends of the 10 CFR 54.4(a)(2) scoping boundary and the safety-nonsafety interface.

In its response dated May 12, 2010, the applicant provided the location of the seismic anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's response to RAI 2.3.3.25-01 acceptable. Therefore, the staff's concern described in RAI 2.3.3.25-01 is resolved.

2.3.3.25.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal. In addition, the staff's review determined whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes the applicant has appropriately identified the SFC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the SFC system mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.26 Switchgear and Penetration Area Ventilation System

2.3.3.26.1 Summary of Technical Information in the Application

LRA Section 2.3.3.26 describes the switchgear and penetration area ventilation system, which is a safety-related, normally operating, mechanical system designed to maintain acceptable levels of temperature and cleanliness in the switchgear rooms, electrical penetration area, and the ventilation equipment room (chiller room).

The purpose of the switchgear and penetration area ventilation system is to maintain acceptable levels of temperature and cleanliness in the switchgear rooms, electrical penetration area, and the ventilation equipment room (chiller room). This is achieved through two supply fans: one switchgear room exhaust fan and one electrical penetration exhaust fan to maintain area temperatures under all conditions. The switchgear and penetration area ventilation system also provides a slightly positive pressure and isolation capabilities for fire conditions in the switchgear rooms and electrical penetration areas.

LRA Table 2.3.3-26 identifies the components subject to an AMR for the switchgear and penetration area ventilation system by component type and intended function.

2.3.3.26.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the switchgear and penetration area ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the switchgear and penetration area ventilation system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

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

- 2.3.4.1 auxiliary feedwater system
- 2.3.4.2 main condensate and feedwater system
- 2.3.4.3 main condenser and air removal system
- 2.3.4.4 main steam system
- 2.3.4.5 main turbine and auxiliaries system

2.3.4.1 Auxiliary Feedwater System

2.3.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the AFW system. The AFW system is a standby, steam and power conversion mechanical system designed to provide feedwater to the SGs for heat removal from the RCS under normal and accident conditions. These accident conditions include the loss of normal feedwater, SG tube rupture, MS or feedwater line break, and small break LOCA. The AFW system is comprised of three pumps (two motor-driven pumps and one turbine-driven pump), one storage tank, and the necessary piping, valves, and instrumentation designed to provide two redundant cooling loops. The loops are designed such that each motor-driven pump is capable of discharging through a flow nozzle into two lines directing flow into two SGs. The turbine-driven pump provides flow to all four SGs.

LRA Table 2.3.4-1 identifies the components subject to an AMR for the AFW system by component type and intended function.

2.3.4.1.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the AFW system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the AFW system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 Main Condensate and Feedwater System

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes the MCFW system. The MCFW system is a normally operating mechanical system designed to maintain water level in the SGs throughout all modes of normal plant operation. The MCFW system is comprised of three condensate pumps, three parallel strings of low pressure feedwater heaters (five heaters per string), two feedwater pumps, three parallel strings of high pressure feedwater heaters (one heater per string), and the required piping, valves, instrumentation, and controls.

The purpose of the MCFW system is to maintain SG water level during all modes of normal plant operation. The MCFW system accomplishes this by heating deaerated condensate from the main condenser and delivering it to the SGs. The MCFW system delivers the water to the SGs to match the steam demand for the turbine load.

LRA Table 2.3.4-2 identifies the components subject to an AMR for the MCFW system by component type and intended function.

2.3.4.2.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the MCFW system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the MCFW system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 Main Condenser and Air Removal System

2.3.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 describes the MCAR system which consists of two plant systems: main condenser and condenser air removal. The MCAR system is comprised of the steam side of the main condenser including the three condenser hot wells, the three condenser vacuum pumps, one priming tank vacuum pump, waterbox priming tank, and the associated valves and piping. The MCAR system is a normally operating mechanical system designed primarily to condense and deaerate steam from the main turbine.

The purpose of the main condenser portion of the MCAR system is to recover water used in the steam cycle by condensing and deaerating unused steam. The purpose of the condenser air removal portions of the MCAR system is to allow the main condenser to operate at vacuum for peak efficiency.

LRA Table 2.3.4-3 identifies the components subject to an AMR for the MCAR system by component type and intended function.

2.3.4.3.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the MCAR system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the MCAR system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.4 Main Steam System

2.3.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 describes the MS system. The MS system is comprised of flow restricting nozzles, safety valves, atmospheric relief valves, main steam isolation valves (MSIVs), mixing bottle, and the necessary piping, valves, and instrumentation designed to provide steam to the high pressure turbine to accomplish its design functions. The MS system is a normally operating mechanical system designed to provide a flow path for the flow of saturated steam between the SG outlets to the high pressure turbine inlets. The MS system also supplies saturated steam to the steam dump system (turbine bypass), moisture separator reheaters, MS coils, the turbine gland seal system, the turbine-driven AFW pump, SG feed pump turbines, and high pressure turbine cylinder heating steam.

The purpose of the MS system is to direct saturated steam from four SGs to the high pressure turbines. It accomplishes this purpose by directing the steam generated by the SGs into the high pressure turbine through piping and piping components. MSIVs are installed in each MS line at the outlet of each SG. The MSIVs close automatically on the initiation of a steam line isolation signal. Flow limiters (venturi-type restrictor) are provided in each steam line. They are designed to increase the margin to departure from nucleate boiling, and thereby reduce fuel clad damage, by limiting steam flow rate consequent to a steam line rupture and thereby reducing the cooldown rate of the primary system. Flow limiters are also provided with steam flow transmitters, which provide inputs to the reactor protection system.

LRA Table 2.3.4-4 identifies the components subject to an AMR for the MS system by component type and intended function.

2.3.4.4.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the MS system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the MS system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.5 Main Turbine and Auxiliaries System

2.3.4.5.1 Summary of Technical Information in the Application

LRA Section 2.3.4.5 describes the MTA system which consists of the following plant systems: the turbine electrohydraulic control system, the gland sealing steam and leak off (turbine) system, the moisture separator reheater steam and drains system, the turbine auxiliaries cooling system, the turbine drains system, the main turbine lube oil system, and the main turbine system. The MTA system is a normally operating mechanical system designed to use steam from the MS system to provide motive force for the main generator.

The overall purpose of the MTA system is to provide motive force for the main generator to generate electrical power for distribution to the grid. The purpose of the turbine electrohydraulic control system is to control turbine valve movement, which in turn controls MS flow at the inlet to the main turbine. The purpose of the gland sealing steam and leak off (turbine) system is to use

MS to seal the annular openings where the main turbine shaft emerges from the casings, preventing steam outleakage and air inleakage along the shaft. The purpose of the moisture separator reheater steam and drains system is to dry and reheat MS from the outlet of the high-pressure turbine and supply it to the low pressure turbines to increase cycle efficiency. The purpose of the turbine auxiliaries cooling system is to provide cooling water to the turbine generator auxiliary components, as well as other plant components.

LRA Table 2.3.4-5 identifies the components subject to an AMR for the MTA system by component type and intended function.

2.3.4.5.2 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the MTA system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the MTA system 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 describes the following structures:

- auxiliary building
- component supports commodity group
- containment structure
- fire pump house
- fuel handling building
- office buildings
- penetration areas
- pipe tunnel
- piping and component insulation commodity group
- station blackout yard buildings
- service building
- service water accumulator enclosures
- service water intake
- shoreline protection and dike
- switchyard
- turbine building
- yard structures

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant identified and listed passive, long-lived SCs that are within the scope of the period of extended operation and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that there were no omissions of structural components that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the information provided in the LRA was performed in the same manner for all structures. The objective of the review was to determine if the structural components that appeared to meet the scoping criteria specified in the Rule were identified by the applicant as being within the scope of license renewal, in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive SCs were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

To perform its evaluation, the staff used the guidance in SRP-LR Section 2.4, "Scoping and Screening Results: Structures," and reviewed the applicable LRA sections, focusing its review on components that had not been identified as within the scope of license renewal.

The staff reviewed the Salem Unit 1 and Unit 2 UFSAR for each structure to determine if the applicant had omitted components, with intended functions delineated in accordance with 10 CFR 54.4(a), from the scope of license renewal. The staff also reviewed the UFSAR to determine if all intended functions delineated in 10 CFR 54.4(a) were specified in the LRA. If omissions were identified, the staff requested additional information to resolve the discrepancies.

Once the staff completed its review of the scoping results, the staff evaluated the applicant's screening results. For those components with intended functions, the staff sought to determine: (1) if the functions are performed with moving parts or a change in configuration or properties, or (2) if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that did not meet either of these criteria, the staff sought to confirm that these structural components were subject to an AMR as required by 10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

2.4.1 Auxiliary Building

2.4.1.1 Summary of Technical Information in the Application

LRA Section 2.4.1 describes the auxiliary building. The auxiliary building, which includes the inner penetration areas, is a reinforced concrete structure located between the Salem Unit 1 and Unit 2 containment structures. The auxiliary building is classified as a Category I (seismic) structure designed to maintain its structural integrity during and following postulated DBAs and extreme environmental conditions. The auxiliary building SCs include reinforced concrete elements of the building, cable trays, concrete embedments, masonry walls, doors, hatches, compressible joints and seals, conduit, expansion or control joints, racks, frames, enclosures, structural steel, miscellaneous steel, bolting, penetration sleeves, penetration seals, pipe whip restraints, missile shields, pipe encapsulation sleeves, spray shields, RHR sump pit and liner, pipe alley and trench, roofing membrane, and tube track. Also included in the boundary of this structure are the blowout panels, the roof blowout panel extension, the roof missile shields for diesel intake, exhaust and building ventilation, and the air discharge penthouse.

The purpose of the auxiliary building is to provide structural support, shelter, and protection to SSCs housed within the building during normal plant operation, and during and following postulated DBAs and extreme environmental conditions.

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

2.4.1.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the auxiliary building SCs 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).

2.4.2 Component Supports Commodity Group

2.4.2.1 Summary of Technical Information in the Application

LRA Section 2.4.2 describes the component supports commodity group which consists of structural elements and specialty components designed to transfer the load applied from an SSC to the building structural element or directly to the building foundation. Supports include seismic anchors or restraints, frames, constant and variable spring hangers, rod hangers, sway struts, guides, stops, design clearances, straps, clamps, and clevis pins. Specialty components include snubbers, sliding surfaces, and vibration isolation elements. The commodity group is comprised of the following supports:

- supports for American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 piping and components
- supports for cable trays; conduits; heating, ventilation, and air conditioning (HVAC) ducts; tube tracks; instrument tubing; and non-ASME piping and components
- supports for racks, panels, cabinets and enclosures for electrical equipment, and instrumentation
- supports for the EDGs, HVAC system components, and other miscellaneous mechanical equipment
- supports for platforms, pipe whip restraints, jet impingement shields, masonry walls, and other miscellaneous structures

The purpose of the component supports commodity group is to transfer gravity, thermal, seismic, and other lateral loads imposed on or by the system, structure, or component to the supporting building structural element or foundation. The commodity group provides physical support and shelter for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of function(s).

LRA Table 2.4-2 identifies the components subject to an AMR for the component supports commodity group by component type and intended function.

2.4.2.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the component supports commodity group SCs 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).

2.4.3 Containment Structure

2.4.3.1 Summary of Technical Information in the Application

LRA Section 2.4.3 describes the containment structure. The Salem Unit 1 and Unit 2 containment buildings are reinforced concrete containments with a cylindrical wall, a foundation mat, and a hemispherical dome roof. The cylindrical wall, the foundation mat, and the dome roof are reinforced with conventional mild steel reinforcing. The inside surface of the containment building is lined with a carbon steel liner to ensure a high degree of leak tightness in the event of a postulated accident. The nominal liner plate thickness is ¼ inch at the foundation mat and ½ inch at the dome. The lower portions of the cylindrical liner are insulated to avoid buckling of the liner due to restricted radial growth when subjected to a rise in temperature. The containment penetrations include the equipment hatch, personnel airlocks, piping penetrations, including the fuel transfer tube penetration, and electrical penetrations.

The purpose of the containment structure is to support and protect the enclosed vital mechanical and electrical equipment, including the RV, the RCS, the SGs, pressurizer, and auxiliary and engineered safety features systems required for safe operation and shutdown of the reactor. The containment building also provides a reliable final barrier against the escape of fission products to ensure the leakage limits are not exceeded and fission product releases are within 10 CFR Part 20 during normal plant operation and 10 CFR Part 100 (10 CFR 50.67) during the postulated DBAs.

LRA Table 2.4-3 identifies the components subject to an AMR for the containment structure by component type and intended function.

2.4.3.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the containment structure SSCs 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).

2.4.4 Fire Pump House

2.4.4.1 Summary of Technical Information in the Application

LRA Section 2.4.4 describes the fire pump house. The major components housed in the building include the diesel-driven fire pumps and jockey pumps, associated piping and piping components, controls and instrumentation, and electrical panels and enclosures. Additionally, fresh water pumps, fresh water chlorination tanks and associated fresh water piping and piping components, controls and instrumentation, and electrical panels and enclosures are also housed within the building.

The purpose of the fire pump house is to provide structural support, shelter, and protection for fire protection system, fresh water system, and supporting systems and components.

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

2.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.12 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review of LRA Section 2.4.4, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for the fire pump house.

In RAI 2.4.4-1, dated March 22, 2010, the staff requested that the applicant provide additional information regarding whether the fire pump house roof insulation had been included within the scope of license renewal and subject to an AMR. Specifically, the staff requested that the applicant indicate whether the component was not included due to oversight and provide a description of the scoping and an AMR if an oversight had occurred. Additionally, the staff requested that the applicant provide the basis for its exclusion, if the applicant concluded that the insulation was excluded from the scope of license renewal.

In its response to the RAI, dated April 15, 2010, the applicant stated that the roof insulation was not included within the scope of license renewal and is not subject to an AMR, based on the location of the insulation between the built up roofing and the roof slab. The built up roofing includes the roofing membrane, which prevents water intrusion into the roofing insulation and subsequently, prevents the degradation of the underlying roofing insulation. Furthermore, the applicant indicated in LRA Section 2.4.4 that the roofing membrane of the fire pump house is within the scope of license renewal and is subject to an AMR. Based on its review, the staff finds the response to RAI 2.4.4-1 acceptable because the insulation is not within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(3) due to the fact that the insulation does not provide physical support or shelter and protection for SSCs relied upon in safety analyses or plant evaluations that demonstrate compliance with the NRC regulation for fire protection (10 CFR 50.48). Additionally, those SSCs which do meet the above criteria have been demonstrated by the applicant to have been adequately addressed in LRA Section 2.4.4. The staff's concern described in RAI 2.4.4-1 is resolved.

2.4.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fire pump house SCs 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).

2.4.5 Fuel Handling Building

2.4.5.1 Summary of Technical Information in the Application

LRA Section 2.4.5 describes the fuel handling building which is comprised of two separate fuel handling buildings, Salem Unit 1 and Unit 2. The buildings are mirror images of each other reflected about the east-west Salem center line. The buildings are classified Category I (seismic) structures, designed to maintain their structural integrity during and following postulated DBAs and extreme environmental conditions. Each building contains a spent fuel storage pool, new fuel storage pit, fuel transfer pool, a decontamination pit, a sump room, and compartments that house spent fuel pool cooling equipment and supporting systems. The design of the spent fuel storage pool and the fuel transfer pool includes a leak chase system that collects potential leakage through cracks in the seam welds of the stainless steel liners. The leak chase system consists of steel channels embedded in the slabs and in the walls of the two pools. The design is such that any leakage collected in the channels is directed and discharged through 17 drain lines into the sump room trench outside the spent fuel pool in the fuel handling building.

The purpose of the fuel handling building is to provide structural support, shelter, and protection to SSCs housed within it during normal plant operation, and during and following postulated DBAs and extreme environmental conditions. This function is provided to the fuel handling and fuels system, spent fuel pool cooling system, fuel handling building heating and ventilation system, compressed air system, and their supporting systems.

LRA Table 2.4-5 identifies the components subject to an AMR for the fuel handling building by component type and intended function.

2.4.5.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fuel handling building SCs 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).

2.4.6 Office Buildings

2.4.6.1 Summary of Technical Information in the Application

LRA Section 2.4.6 describes the office buildings which consist of the controlled facilities building, the clean facilities building, and the administration building.

The purpose of the office buildings is to provide physical support, shelter, and protection for nonsafety-related SSCs. The buildings also provide shelter and facilities for site management, engineering, chemistry, maintenance, and other site support personnel. The controlled facilities building provides office space, storage space, a machice shop, and a mechanical equipment room.

LRA Table 2.4-6 identifies the components subject to an AMR for the office buildings by component type and intended function. The controlled facilities building and the clean facilities building are within the scope of license renewal. The administration building does not perform an intended function and thus is not within the scope of license renewal.

2.4.6.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the office buildings' SCs 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).

2.4.7 Penetration Areas

2.4.7.1 Summary of Technical Information in the Application

LRA Section 2.4.7 describes the penetration areas which consist of two reinforced concrete enclosed areas: the Salem Unit 1 south outer penetration area and the Salem Unit 2 north outer penetration area. The areas, or structures, are located at the exit of the MS system and the MCFW system piping from the containments en route to the turbine building. The structures are classified as Category I (seismic) structures, designed to maintain their structural integrity during and following postulated DBEs and extreme environmental conditions. A seismic gap separates the structures from the containment buildings to prevent their interaction during the postulated design basis seismic events.

The purpose of the penetration areas is to support and protect safety-related MS and MCFW system piping and components and their supporting mechanical and electrical systems. The structures also provide radiation shielding and protection for the containment structure penetrations.

LRA Table 2.4-7 identifies the components subject to an AMR for the penetration areas by component type and intended function.

2.4.7.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the penetration areas' SCs 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).

2.4.8 Pipe Tunnel

2.4.8.1 Summary of Technical Information in the Application

LRA Section 2.4.8 describes the pipe tunnel as a two-cell reinforced concrete rectangular box section located west of the containment buildings, and adjacent to the west wall of the auxiliary building. The pipe tunnel is classified as a Category I (seismic) structure.

The purpose of the pipe tunnel is to provide structural support for Salem Unit 1 and Unit 2 RWSTs, AFW tanks, and PWSTs. The tunnel also provides structural support, shelter, and protection for the SW system piping and piping components and supporting electrical systems.

LRA Table 2.4-8 identifies the components subject to an AMR for the pipe tunnel by component type and intended function.

2.4.8.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the pipe tunnel SCs 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).

2.4.9 Piping and Component Insulation Commodity Group

2.4.9.1 Summary of Technical Information in the Application

LRA Section 2.4.9 describes the piping and component insulation commodity group. The piping and component insulation commodity group is comprised of prefabricated blankets, modules, or panels engineered as integrated assemblies to fit the surface to be insulated and to fit easily against the piping and components. The insulation includes metallic and non-metallic materials.

The purpose of piping and component insulation is to: (1) improve thermal efficiency, (2) minimize heat loads on the HVAC systems, (3) provide for personnel protection, (4) prevent freezing of heat traced piping, and (5) protect against sweating of cold piping and components. Insulation of piping within containment penetrations, in conjunction with the penetration cooling system, limits the concrete temperature adjacent to the embedded sleeve to within an allowable limit.

LRA Table 2.4-9 identifies the components subject to an AMR for the piping and component insulation commodity group by component type and intended function.

2.4.9.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the piping and component insulation commodity group SCs 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).

2.4.10 Station Blackout Yard Buildings

2.4.10.1 Summary of Technical Information in the Application

LRA Section 2.4.10 describes the SBO yard buildings, which are nonsafety-related structures designed to commercial grade standards. The structures are separated from safety-related SSCs such that its failure would not impact a safety-related function.

The purpose of the SBO yard buildings is to provide physical support, shelter, and protection for the SBO diesel-driven air compressor and its auxiliary systems. The compressor is credited for providing control air during an SBO event. Major components housed inside the buildings include the SBO diesel-driven air compressor, regenerative air dryer, after-cooler, transformers, distribution panel, disconnect switch, and piping and piping components.

LRA Table 2.4-10 identifies the components subject to an AMR for the SBO yard buildings by component type and intended function.

2.4.10.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SBO yard buildings SCs 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).

2.4.11 Service Building

2.4.11.1 Summary of Technical Information in the Application

LRA Section 2.4.11 describes the service building which is partitioned into office areas, training areas, main access control into the radiological area, maintenance shops, and facilities for personnel occupying the building. Components inside the building are nonsafety-related except for two AFW system isolation valves within trenches in the basement floor of the building. The service building is nonsafety-related and is classified as a Category III (seismic) structure.

The purpose of the service building is to house equipment, tools, and personnel required for supporting operation of Salem Unit 1 and Unit 2. It provides office space and facilities for plant support personnel, training areas, and maintenance shops.

LRA Table 2.4-11 identifies the components subject to an AMR for the service building by component type and intended function.

2.4.11.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the service building SCs 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).

2.4.12 Service Water Accumulator Enclosures

2.4.12.1 Summary of Technical Information in the Application

LRA Section 2.4.12 describes the SW accumulator enclosures which consist of two enclosures that house Salem Unit 1 and Unit 2 SW system accumulator tanks. Each enclosure is comprised of structural steel frames, metal siding, prefabricated roof panels, and reinforced concrete slab on grade. The steel frames are supported on reinforced concrete footings founded on soil and from reinforced concrete walls of the fuel handling building and the auxiliary building. The structural steel frames and plate, the reinforced concrete footings, and other components that provide structural support or shelter and protection for the accumulator tanks are classified Category I (seismic) structures. The remaining portions of the enclosures are nonsafety-related designed to maintain their structural integrity during DBEs (seismic II/I) to prevent interaction with the safety-related SW system components.

The purpose of the SW accumulator enclosures is to provide structural support, shelter, and protection for safety-related SW system accumulator tanks and associated SW system piping and piping components. The enclosures also house nonsafety-related SSCs whose failure could impact a safety-related function.

LRA Table 2.4-12 identifies the components subject to an AMR for the SW accumulator enclosures by component type and intended function.

2.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.12 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review of LRA Section 2.4.12, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for the SW accumulator enclosures.

In RAI 2.4.12-1, dated March 22, 2010, the staff requested that the applicant provide additional information to confirm that the cable trays, conduits, panels, racks, cabinets, and other enclosures have been included within the scope of license renewal and subject to an AMR. Specifically, the staff requested that the applicant indicate whether these components were not included due to oversight and provide a description of the scoping and an AMR, if an oversight had occurred. Additionally, the staff requested that the applicant provide the bases for their exclusion, if the applicant concluded that these components were excluded from the scope of license renewal.

In its response dated April 15, 2010, the applicant stated that these components were included within the scope of license renewal and are subject to an AMR due to the fact that these components perform intended functions which meet the criteria found within 10 CFR 54.4(a). Additionally, the applicant indicated that these components were included within LRA Section 2.4.12 under "Miscellaneous Steel (catwalks, handrails, ladders, platforms, etc.)." Based on its review, the staff finds the response to RAI 2.4.12-1 acceptable because the applicant has clarified that these components are within the scope of license renewal, consistent with the criteria outlined in 10 CFR 54.4(a), and subject to an AMR. The staff's concern described in RAI 2.4.12-1 is resolved.

2.4.12.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SW accumulator enclosures SCs 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).

2.4.13 Service Water Intake

2.4.13.1 Summary of Technical Information in the Application

LRA Section 2.4.13 describes the SW intake structure as a reinforced concrete structure located along the western shoreline of the facility and on the eastern bank of the Delaware River. The SW intake structure is designed to protect the enclosed portion of the SW system and related vital components under postulated environmental and DBE loadings and is designated as safety-related and Category I (seismic).

The purpose of the SW intake structure is to support and protect the enclosed portion of the SW system and its related vital components under postulated environmental and DBE loading conditions and to provide access to a reliable source of cooling water for plant safe shutdown from the Delaware River. Major components housed inside the building include electrical switchgear, miscellaneous electrical equipment and components and their enclosures, instrumentation and their enclosures as applicable, trash racks, SW piping, SW pumps, and the traveling water screens. The SW intake structure also houses or supports nonsafety-related equipment including cranes and hoists.

LRA Table 2.4-13 identifies the components subject to an AMR for the SW intake by component type and intended function.

2.4.13.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SW intake SCs 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).

2.4.14 Shoreline Protection and Dike

2.4.14.1 Summary of Technical Information in the Application

LRA Section 2.4.13 describes the shoreline protection and dike as a shoreline protective structural feature comprised primarily of rock, armor stone, steel sheet piles, cofferdams, intake structures, and concrete which is located along the Delaware River shoreline of Artificial Island.

The purpose of the shoreline protection and dike is to provide a flood protection barrier, between the Delaware River and the plant site, which limits wave run-up during design basis storm surge events to elevations on buildings sealed for external flooding.

LRA Table 2.4-14 identifies the components subject to an AMR for the shoreline protection and dike by component type and intended function.

2.4.14.2 Staff Evaluation

The staff reviewed LRA Section 2.4.14 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review of LRA Section 2.4.14, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for the shoreline protection and dike.

In RAI 2.4.14-1, dated March 22, 2010, the staff requested that the applicant provide additional information to confirm that the cofferdams have been included within the scope of license renewal and subject to an AMR. Specifically, the staff requested that the applicant indicate whether the cofferdams were not included due to oversight and provide a description of the scoping and an AMR, if an oversight had occurred. Additionally, the staff requested that the applicant provide the bases for their exclusion, if the applicant concluded that these components were excluded from the scope of license renewal.

In its response to the RAI, dated April 15, 2010, the applicant stated that the cofferdams are included within the scope of license renewal and are subject to an AMR. The applicant indicated that the cofferdams consist of sheet piles, which are listed in LRA Section 2.4-14 as being within the scope of license renewal and subject to an AMR due to the fact that these components perform intended functions which meet the criteria found within 10 CFR 54.4(a). Based on its review, the staff finds the response to RAI 2.4.14-1 acceptable because the applicant has clarified that these components are within the scope of license renewal and subject to an AMR, consistent with the criteria outlined in 10 CFR 54.4(a). The staff's concern described in RAI 2.4.14-1 is resolved.

2.4.14.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any

SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the shoreline protection and dike SCs 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).

2.4.15 Switchyard

2.4.15.1 Summary of Technical Information in the Application

LRA Section 2.4.15 describes the switchyard which consists of reinforced concrete and steel components, which include steel piles, equipment foundations, transmission towers, duct banks, manholes, trenches, sumps, structural bolting, embedments, and concrete anchors.

The purpose of the switchyard is to provide physical support, shelter, and protection to the 13-kV system and the offsite 500-kV system components and commodities. The systems are relied upon to provide offsite power during SBO event restoration. The offsite 500-kV system consists of three 500-kV transmission lines connected to a breaker-and-a-half design with four 500-kV–13-kV transformers. The offsite 500-kV system receives site generated power and transmits it over three transmission lines to the Public Service Electric and Gas electric transmission network.

LRA Table 2.4-15 identifies the components subject to an AMR for the switchyard by component type and intended function.

2.4.15.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the switchyard SCs 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).

2.4.16 Turbine Building

2.4.16.1 Summary of Technical Information in the Application

LRA Section 2.4.16 describes the turbine building as a multi-story structure approximately 170 feet by 610 feet in plan area, comprised of structural steel framing, precast concrete panels, metal siding, masonry walls, and reinforced concrete walls, slabs, foundation mat, and roof.

The purpose of the building is to provide structural support, shelter, and protection for nonsafety-related SSCs during normal plant operation. The turbine building contains steam and power conversion systems components, and support systems and components necessary to support fire protection, SBO, and ATWS. The turbine building contains certain nonsafety-related electrical and mechanical components which perform intended functions considered important to safety by providing input signals and actuation devices for the reactor trip and engineered safety features actuation systems and by providing a means for feedwater isolation.

LRA Table 2.4-16 identifies the components subject to an AMR for the turbine building by component type and intended function.

2.4.16.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the turbine building SCs 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).

2.4.17 Yard Structures

2.4.17.1 Summary of Technical Information in the Application

LRA Section 2.4.17 describes the yard structures which includes the compressed gas storage areas, tank foundations and dikes, pipe support structures, circulating water system piping foundations, turbine crane runway extensions, manholes, handholes and duct banks, miscellaneous yard structures, miscellaneous yard enclosures, transformer foundations, trenches, and yard drainage system.

The purpose of the yard structures is to provide structural support, shelter, and protection for safety-related and nonsafety-related components and commodities, including components credited for SBO, fire protection, and ATWS.

LRA Table 2.4-17 identifies the components subject to an AMR for the yard structures by component type and intended function.

2.4.17.2 Conclusion

The staff followed the evaluation methodology discussed in SER Section 2.4 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff finds no such omissions. In addition, the staff's review determined whether the applicant failed to identify any SCs subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the yard structure SCs 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).

2.5 Scoping and Screening Results: Electrical and Instrumentation and Controls 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 component commodity groups.

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

The staff's evaluation of the 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, 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 in accordance with 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 Controls Component Commodity Groups

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and I&C systems. The scoping method includes all plant electrical and I&C components. Evaluation of electrical systems includes electrical and I&C components in mechanical systems. The plant-wide basis approach for the review of plant equipment eliminates the need to indicate each unique component and its specific location and precludes improper exclusion of components from an AMR.

The 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.

LRA Table 2.5.2-1 identifies the following electrical component commodity group component types and their intended function within the scope of license renewal and subject to an AMR:

- cable connections-metallic parts/electrical continuity
- connector contacts for electrical connectors exposed to borated water leakage/electrical continuity
- fuse holders/electrical continuity
- high-voltage insulators/insulation-electrical
- insulated cables and connections/electrical continuity
- metal enclosed bus/electrical continuity, insulation-electrical, shelter, and protection
- switchyard bus and connections/electrical continuity

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 in accordance with 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 (ADAMS Accession No. ML020920464), "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 in SRP-LR Section 2.5.2.1.1, states:

> 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, up to and including, switchyard breakers (including the associated controls and structures) within the scope of license renewal. Figure 2.1-2, “Salem Offsite Power for SBO,” indicates the SBO recovery path and electrical distribution systems. LRA Section 2.5.1 states that the scoping boundary consists of six 500-kV switchyard circuit breakers (10X, 11X, 20X, 21X, 30X, and 31X). Consequently, the staff concludes that the scoping is consistent with the guidance issued on April 1, 2002, and later incorporated in SRP-LR Section 2.5.2.1.1.

The applicant has determined that cable tie-wraps are not within the scope of license renewal and are not subject to an AMR. In the LRA, the applicant stated that cable tie-wraps are used to bundle wires and cables together to maintain the cable runs neat and orderly. The cable tie-wraps are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius or maintaining cables within vertical raceways. 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 transmission conductors and connections commodity group consists of a portion of the circuits that supply power from the main generator to the electric power grid, as stated in LRA Section 2.5.2.3. Since these components are not in the SBO recovery path and do not perform any intended functions for license renewal, the staff finds that transmission conductors and connections are not subject to an AMR.

2.5.1.3 Conclusion

The staff reviewed the evaluation methodology discussed in SER Section 2.5 and reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff has found no such omissions. In addition, the staff’s review determined whether the applicant failed to identify any components subject to an AMR. The staff finds no such omissions. On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the electrical and I&C systems 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).

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.” The staff finds that the applicant’s scoping and screening methodology is consistent with the requirements of 10 CFR 54.21(a)(1), and the staff’s position on the treatment of safety-related and nonsafety-related SSCs within the scope of license renewal and the SCs requiring an AMR are 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 SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

With regard to these matters, the staff concludes that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and any changes made to the CLB, to comply with 10 CFR 54.21(a)(1), are in accordance with 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 Salem Nuclear Generating Station Units 1 and 2 (Salem), by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

In Appendix B of its license renewal application (LRA), PSEG Nuclear, LLC (PSEG or the applicant) described the 48 AMPs it relies on to manage or monitor the aging of passive and 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, "Generic Aging Lessons Learned (GALL) Report," Revision 1, dated September 2005. 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 SCs for license renewal without change. 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 the programs at its facility correspond to those reviewed and approved in the GALL Report.

The purpose of the GALL Report is to provide the staff with 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 used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a reference for applicants and staff reviewers to quickly identify those 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 associated with 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 performed its review in accordance with the requirements of Title 10, Part 54 of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"; the guidance provided in NUREG-1800, "Standard Review

Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Revision 1, dated September 2005; and the guidance provided in the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMRs and associated AMPs during the weeks of February 8 and February 15, 2010, as described in the "Audit Report Regarding the Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application," dated November 9, 2010. The onsite audits and reviews are designed to maximize the 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 by letter dated August 18, 2009, that followed the standard LRA format, as determined by the NRC and the Nuclear Energy Institute (NEI). This LRA format incorporates lessons learned from the staff's reviews of previous LRAs which used a format developed from information gained during a staff-NEI demonstration project conducted to evaluate the use of the GALL Report in the LRA review process.

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

(1) 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 is the first table type in LRA Section 3.

(2) 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 is the second table type in LRA Section 3, and "y" indicates the system table number.

The contents of the previous applications and the Salem application are essentially the same. The intent of the format used for the Salem LRA was to modify the tables in Chapter 3 to provide additional information that would assist the staff in its review. In each Table 1, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In each Table 2, the applicant identified the linkage between the scoping and screening results in Chapter 2 and the AMRs in LRA Chapter 3.

3.0.1.1 Overview of Table 1s

Each Table 3.x.1 (Table 1) provides a summary comparison of how the facility aligns with the corresponding tables of the GALL Report. The table is essentially the same as Tables 1 through 6 provided in the GALL Report, Volume 1, except that the "Type" column has been replaced by an "Item Number" column and the "Related Generic Item" and "Unique Item" columns have been replaced by a "Discussion" column. The "Discussion" column is used by the applicant to provide clarifying and amplifying information.

The following are some 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 the GALL Report assumptions
- discussion of how the line is consistent with the corresponding line item in the GALL Report when this consistency may not be obvious
- discussion of how the item is different from the corresponding line item in the GALL Report (e.g., when an exception is taken to a GALL Report AMP)

The format of Table 1 allows the staff to align a specific Table 1 row with the corresponding GALL Report table row so that the consistency can be efficiently checked.

3.0.1.2 Overview of Table 2s

Each Table 3.x.2-y (Table 2) provides the detailed results of the AMRs for those components identified in LRA Section 2 as subject to an AMR. The LRA contains a Table 2 for each of the systems or components within a system grouping (e.g., reactor coolant systems, engineered safety features, auxiliary systems, etc.). For example, the engineered safety features (ESF) group contains tables specific to the containment spray system, residual heat removal (RHR) system, and safety injection system. Each Table 2 consists of the following nine columns:

(1) Component Type – The first column identifies the component types from LRA Section 2 subject to an AMR. The component types are listed in alphabetical order.

(2) Intended Function – The second column contains the license renewal intended functions for the listed component types. Definitions of intended functions are contained in LRA Table 2.1-1.

(3) Material – The third column lists the particular materials of construction for the component type.

(4) Environment – The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated; a list of these environments is provided in LRA Tables 3.0-1 and 3.0-2.

(5) 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.

(6) Aging Management Programs – The sixth column lists the AMPs that the applicant used to manage the identified aging effects.

(7) NUREG-1801 Volume 2 Item – The seventh column lists the GALL Report item(s) that the applicant identified as similar to the AMR results in the LRA. The applicant compared each combination of component type, material, environment, AERM, and AMP in Table 2 of the LRA to the items in the GALL Report. If there were no corresponding items in the GALL Report, the applicant left the column blank. In this way, the applicant identified the AMR results in the LRA tables that corresponded to the items in the GALL Report tables.

(8) Table 1 Item – The eighth column lists the corresponding summary item number from Table 1. If the applicant identifies AMR results in Table 2 that are consistent with the GALL Report, then the associated Table 3.x.1 line summary item number should be listed in Table 2. If there is no corresponding item in the GALL Report, then column eight is left blank. That way, the information from the two tables can be correlated.

(9) Notes – The ninth column lists the corresponding notes that the applicant used to identify how the information in Table 2 aligns with the information in the GALL Report. The notes identified by letters were developed by an NEI working group and will be used in future LRAs. Any plant-specific notes are identified by a number and provide additional information concerning the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

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

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

(3) For other items, the staff conducted a technical review pursuant to 10 CFR 54.21(a)(3).

These audits and technical reviews determine whether the effects of aging on SCs can be adequately managed so that the intended functions can be maintained 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 those AMPs for which the applicant had claimed consistency with the GALL Report AMPs, the staff conducted either an audit or a technical review to confirm that the applicant's AMPs were consistent with the GALL Report. For each AMP that had one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the AMP, as modified, would adequately manage the aging effect(s) for which it was credited. For AMPs that were not addressed 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, which follow.

(1) Scope of the Program: The scope of the program should include the specific SCs subject to an AMR for license renewal.

(2) Preventive Actions: Preventive actions should prevent or mitigate aging degradation.

(3) Parameters Monitored or Inspected: Parameters monitored or inspected should be linked to the degradation of the particular structure or component's intended function(s).

(4) Detection of Aging Effects: Detection of aging effects including such aspects as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections should occur before there is a loss of structure or component intended function(s).

(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 and effective corrective actions have been completed.

(9) Administrative Controls: Administrative controls should provide 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 functions 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 the AMP Audit Report and summarized in SER Section 3.0.3.

The staff reviewed the applicant's corrective action program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the corrective action program included assessments of the following program elements: (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls."

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

Table 2 contains information concerning whether the AMRs align with the AMRs identified in the GALL Report. For a given AMR in Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular component type within a system. The AMRs that correlate between a combination in Table 2 and a combination in the GALL Report were identified by a referenced item number in column seven, “NUREG-1801 Volume 2 Line Item.” The staff also conducted onsite audits to verify the correlation. A blank column seven indicates that the applicant was unable to locate an appropriate corresponding combination in the GALL Report. The staff conducted a technical review of these combinations not consistent with the GALL Report. The next column, “Table 1 Item,” provides a reference number that indicates the corresponding row in Table 1.

3.0.2.3 UFSAR Supplement

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

3.0.2.4 Documentation and Documents Reviewed

In performing its review, the staff used the LRA, LRA supplements, SRP-LR, GALL Report, and request for additional information (RAI) responses. Also, during the onsite audit, the staff examined the applicant’s justifications, as documented in the Audit Summary Report, to verify that the applicant’s activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant’s license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

SER Table 3.0.3-1 below presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the GALL Report AMP that the applicant claimed its AMP was consistent with, if applicable, and the SSCs for managing or monitoring aging. The section of the SER, in which the staff’s evaluation of the program is documented, is also provided.

Table 3.0.3-1 Salem Units 1 and 2 Aging Management Programs

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	A.2.1.1 B.2.1.1	Existing	Consistent	XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	3.0.3.1.1
Water Chemistry	A.2.1.2 B.2.1.2	Existing	Consistent	XI.M2, “Water Chemistry”	3.0.3.1.2
Reactor Head Closure Studs	A.2.1.3 B.2.1.3	Existing	Consistent	XI.M3, “Reactor Head Closure Studs”	3.0.3.1.3
Boric Acid Corrosion	A.2.1.4 B.2.1.4	Existing	Consistent	XI.M10, “Boric Acid Corrosion	3.0.3.1.4
Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	A.2.1.5 B.2.1.5	Existing	Consistent	XI.M11A, “Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors”	3.0.3.1.5
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	A.2.1.6 B.2.1.6	New	Consistent	XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)”	3.0.3.1.6
PWR Vessel Internals	A.2.1.7 B.2.1.7	New	Consistent	XI.M16, “PWR Vessel Internals”	3.0.3.1.7
Flow-Accelerated Corrosion	A.2.1.8 B.2.1.8	Existing	Consistent with Exception	XI.M17, “Flow-Accelerated Corrosion”	3.0.3.2.1
Bolting Integrity	A.2.1.9 B.2.1.9	Existing	Consistent with Exception and Enhancement	XI.M18, “Bolting Integrity”	3.0.3.2.2
Steam Generator Tube Integrity	A.2.1.10 B.2.1.10	Existing	Consistent	XI.M19, “Steam Generator Tube Integrity”	3.0.3.1.8
Open-Cycle Cooling Water System	A.2.1.11 B.2.1.11	Existing	Consistent	XI.M20, “Open-Cycle Cooling Water System”	3.0.3.1.9

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Closed-Cycle Cooling Water System	A.2.1.12 B.2.1.12	Existing	Consistent with Exception and Enhancements	XI.M21, “Closed-Cycle Cooling Water System”	3.0.3.2.3
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	A.2.1.13 B.2.1.13	Existing	Consistent with Enhancements	XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	3.0.3.2.4
Compressed Air Monitoring	A.2.1.14 B.2.1.14	Existing	Consistent	XI.M24, “Compressed Air Monitoring”	3.0.3.1.10
Fire Protection	A.2.1.15 B.2.1.15	Existing	Consistent with Exception and Enhancements	XI.M26, “Fire Protection”	3.0.3.2.5
Fire Water System	A.2.1.16 B.2.1.16	Existing	Consistent with Enhancements	XI.M27, “Fire Water System”	3.0.3.2.6
Aboveground Steel Tanks	A.2.1.17 B.2.1.17	Existing	Consistent with Enhancements	XI.M29, “Aboveground Steel Tanks”	3.0.3.2.7
Fuel Oil Chemistry	A.2.1.18 B.2.1.18	Existing	Consistent with Exceptions and Enhancements	XI.M30, “Fuel Oil Chemistry”	3.0.3.2.8
Reactor Vessel Surveillance	A.2.1.19 B.2.1.19	Existing	Consistent with Enhancements	XI.M31, “Reactor Vessel Surveillance”	3.0.3.2.9
One-Time Inspection	A.2.1.20 B.2.1.20	New	Consistent	XI.M32, “One-Time Inspection”	3.0.3.1.11
Selective Leaching of Materials	A.2.1.21 B.2.1.21	New	Consistent	XI.M33, “Selective Leaching of Materials”	3.0.3.1.12
Buried Piping Inspection	A.2.1.22 B.2.1.22	Existing	Consistent with Enhancement	XI.M34, “Buried Piping and Tanks Inspection”	3.0.3.2.10
One-Time Inspection of ASME Code Class 1 Small-Bore Piping	A.2.1.23 B.2.1.23	New	Consistent with Exception	XI.M35, “One-Time Inspection of ASME Code Class 1 Small-Bore Piping”	3.0.3.2.11
External Surfaces Monitoring	A.2.1.24 B.2.1.24	New	Consistent	XI.M36, “External Surfaces Monitoring”	3.0.3.1.13
Flux Thimble Tube Inspection	A.2.1.25 B.2.1.25	New	Consistent	XI.M37, “Flux Thimble Tube Inspection”	3.0.3.1.14

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	A.2.1.26 B.2.1.26	New	Consistent	XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	3.0.3.1.15
Lubricating Oil Analysis	A.2.1.27 B.2.1.27	Existing	Consistent with Exception	XI.M39, “Lubricating Oil Analysis”	3.0.3.2.12
ASME Section XI, Subsection IWE	A.2.1.28 B.2.1.28	Existing	Consistent with Enhancements	XI.S1, “ASME Section XI, Subsection IWE”	3.0.3.2.13
ASME Section XI, Subsection IWL	A.2.1.29 B.2.1.29	Existing	Consistent	XI.S2, “ASME Section XI, Subsection IWL”	3.0.3.1.16
ASME Section XI, Subsection IWF	A.2.1.30 B.2.1.30	Existing	Consistent	XI.S3, “ASME Section XI, Subsection IWF”	3.0.3.1.17
10 CFR 50, Appendix J	A.2.1.31 B.2.1.31	Existing	Consistent	XI.S4, “10 CFR 50 Appendix J”	3.0.3.1.18
Masonry Wall Program	A.2.1.32 B.2.1.32	Existing	Consistent with Enhancements	XI.S5, “Masonry Wall Program”	3.0.3.2.14
Structures Monitoring Program	A.2.1.33 B.2.1.33	Existing	Consistent with Enhancements	XI.S6, “Structures Monitoring Program”	3.0.3.2.15
RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	A.2.1.34 B.2.1.34	Existing	Consistent with Enhancements	XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants”	3.0.3.2.16
Protective Coating Monitoring and Maintenance Program	A.2.1.35 B.2.1.35	Existing	Consistent	XI.S8, “Protective Coating Monitoring and Maintenance Program”	3.0.3.1.19
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.36 B.2.1.36	New	Consistent	XI.E1, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.1.20

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	A.2.1.37 B.2.1.37	New	Consistent	XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	3.0.3.1.21
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.38 B.2.1.38	New	Consistent	XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.22
Metal Enclosed Bus	A.2.1.39 B.2.1.39	New	Consistent	XI.E4, "Metal Enclosed Bus"	3.0.3.1.23
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.40 B.2.1.40	New	Consistent with Exception	XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.2.17
High Voltage Insulators	A.2.2.1 B.2.2.1	New	Plant-Specific	N/A	3.0.3.3.1
Periodic Inspection	A.2.2.2 B.2.2.2	New	Plant-Specific	N/A	3.0.3.3.2
Aboveground Non-Steel Tanks	A.2.2.3 B.2.2.3	New	Plant-Specific	N/A	3.0.3.3.3
Buried Non-Steel Piping Inspection	A.2.2.4 B.2.2.4	Existing	Plant-Specific	N/A	3.0.3.3.4
Boral Monitoring Program	A.2.2.5 B.2.2.5	Existing	Plant-Specific	N/A	3.0.3.3.5
Nickel Alloy Aging Management	A.2.2.6 B.2.2.6	Existing	Plant-Specific	N/A	3.0.3.3.6
Metal Fatigue of Reactor Coolant Pressure Boundary	A.3.1.1 B.3.1.1	Existing	Consistent with Enhancements	X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary"	3.0.3.2.18

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Environmental Qualification (EQ) of Electric Components	A.3.1.2 B.3.1.2	Existing	Consistent	X.E1, “Environmental Qualification (EQ) of Electric Components”	3.0.3.1.24

3.0.3.1 AMPs That Are Consistent with the GALL Report

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

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Water Chemistry
- Reactor Head Closure Studs
- Boric Acid Corrosion
- Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)
- PWR Vessel Internals
- Steam Generator Tube Integrity
- Open-Cycle Cooling Water System
- Compressed Air Monitoring
- One-Time Inspection
- Selective Leaching of Materials
- External Surfaces Monitoring
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- ASME Section XI, Subsection IWL
- ASME Section XI, Subsection IWF
- 10 CFR 50, Appendix J

- Protective Coating Monitoring and Maintenance Program
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Enclosed Bus
- Environmental Qualification (EQ) of Electric Components

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

Summary of Technical Information in the Application. LRA Section B.2.1.1 describes the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as consistent with GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." The applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes inspections performed to manage cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components exposed to air, reactor coolant, steam, treated water, and treated borated water environments within the scope of license renewal. The applicant stated that the program: (1) provides for periodic visual, surface, and volumetric examination; (2) provides for leakage testing of pressure-retaining piping and components including welds, pump casings, steam generator (SG) components, nozzles and safe ends, valve bodies, integral attachments, and pressure-retaining bolting; and (3) consists of condition monitoring activities that detect degradation of components before loss of intended function.

The applicant stated that its current ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is based on the 1998 Edition through the 2000 Addenda of American Society of Mechanical Engineers (ASME) Code Section XI and that its program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code, as specified in 10 CFR 50.55a, 12 months before the start of the inspection interval.

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

The staff compared elements one through six of the applicant's program with the corresponding elements of GALL AMP XI.M1. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M1, with the exception of the "detection of aging effects" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

The staff noted that the applicant is currently in its third 10-year inservice inspection (ISI) interval and that the current ISI interval does not continue into the period of extended operation.

The staff also noted that during the current interval, the applicant's ISI program includes a risk informed-inservice inspection (RI-ISI) methodology that has been approved for the current interval in accordance with the requirements of 10 CFR 50.55a. The staff further noted that in LRA Section B.2.1.1, the applicant stated that its ISI program uses an alternative method to determine the inspection locations, inspection frequency, and inspection techniques for Class 1 Category B-F and B-J, and Class 2 Category C-F-1 and C-F-2 welds. It was not clear to the staff whether the discussion of alternative inspection methods in the LRA is applicable only to the current inspection interval or whether the discussion also applies to the period of extended operation. In RAI B.2.1.1-01, dated July 12, 2010, the staff requested that the applicant explain why RI-ISI and other alternatives to the requirements of ASME Code Section XI, Subsections IWB, IWC, and IWD are discussed in the LRA's "program description" for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

The applicant's August 10, 2010, response stated that RI-ISI and other alternatives to the ASME Code Section XI requirements were discussed in the LRA because they are contained in the applicant's existing ISI program plan for the third 10-year inspection interval, which was used to evaluate the ISI program against the recommendations in GALL AMP XI.M1. The applicant stated that it recognizes that the license renewal process does not review and approve future station ISI program plans, including RI-ISI and other alternatives to the ASME Code Section XI requirements. The applicant further stated that at the end of the current 10-year ISI interval, it will be required to submit an update to its ISI program plan for staff review in accordance with the requirements of 10 CFR 50.55a.

Based on its audit and review of the applicant's response to RAI B.2.1.1-01, the staff finds that elements one through six of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program are consistent with the corresponding program elements of GALL AMP XI.M1 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.1 summarizes operating experience related to the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant described detection of a weld flaw using dye penetrant examination at Unit 2 in 2000 and identification of weld indications in the 2005 baseline draft report for Salem 2. For the flaw detected in 2000, the applicant stated that documentation of the flaw was entered into the site's corrective action program, additional ultrasonic examinations were performed, and the indication and expansion results were evaluated in accordance with ASME Code Section XI criteria and found to be acceptable. For the baseline indications reported in 2005, the applicant stated that the indications were determined most likely to be weld fabrication indications caused by embedded slag inclusions and oxides that occurred along the weld fusion line. The applicant further stated that corrective actions included an independent structural evaluation related to the indications and improving the workmanship in removing slag from the manufacturing of the Salem Unit 1 replacement reactor vessel head. The applicant stated that these examples demonstrate the program effectively identifies degradation prior to failure and that it provides appropriate guidance for expanded examination, evaluation, repair, or replacement when degradation is found.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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 of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.1 provides the UFSAR supplement for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 1) to ongoing implementation of the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; the RAI responses; and the audit, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Water Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.2 describes the existing Water Chemistry Program as consistent with GALL AMP XI.M2, "Water Chemistry." The applicant stated that the Water Chemistry Program monitors and controls the chemical environment of the primary and secondary systems. The applicant credited the program for the management of the aging effects of cracking, loss of material, reduction of neutron-absorbing capacity and reduction of heat transfer, and the mitigation of stress-corrosion cracking (SCC). The applicant also stated that the primary water portion of the program is consistent with Electric Power Research Institute (EPRI) 1014986, "PWR Primary Water Chemistry Guidelines," Revision 6, and that the secondary water portion of the program is consistent with EPRI 1008224, "PWR Secondary Water Chemistry Guidelines," Revision 6. The applicant further stated that the Water Chemistry Program includes periodic sampling of primary and secondary water for detrimental contaminants specified in EPRI water chemistry guidelines. The applicant identified the reactor vessel, reactor internals, piping, piping elements and piping components, heat exchangers, and tanks as the major components of the primary system.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M2. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M2. Based on its audit, the staff finds that elements one through six of the applicant's Water Chemistry Program are consistent with the corresponding program elements of GALL AMP XI.M2 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.2 summarizes operating experience related to the Water Chemistry Program. The applicant stated that it experienced an unexpected reactor coolant system (RCS) dissolved oxygen (DO) transient after a startup following an SG replacement and that the cause of the DO transient was that sufficient air was left in the RCS to create a hydraulic lock that prevented back flow through the SG U-tubes. As a result of this DO transient, the applicant modified its vacuum refill procedure to prevent a recurrence of this event. The applicant stated that subsequent startups using vacuum refill have resulted in minimal DO in the RCS. The applicant further stated that this operating experience is an example of how the Water Chemistry Program is able to identify unexpected behaviors and modify system operation to prevent a recurrence of initiating events.

The applicant stated that in 2008, it identified an increasing trend in sodium concentrations, which remained below acceptable limits. The applicant also stated that it performed grab samples to confirm the online monitor indications and that it identified the cause of the increase in sodium as a small river water leak into the SG blowdown (SGBD) condenser. The applicant further stated that the SGBD condenser was taken off line as part of a troubleshooting plan and that sodium levels dropped to normal values. The applicant stated that this operating experience demonstrates that the Water Chemistry Program was able to detect, identify, and correct issues based on relatively minor excursions in water chemistry.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.2 provides the UFSAR supplement for the Water Chemistry Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 2) to ongoing implementation of the existing Water Chemistry Program for managing aging of applicable components during the period of extended operation. The staff further notes that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program to manage loss of material and cracking in stainless steel components in a treated borated water environment.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Water Chemistry Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Reactor Head Closure Studs

Summary of Technical Information in the Application. LRA Section B.2.1.3 describes the existing Reactor Head Closure Studs Program as consistent with GALL AMP XI.M3, "Reactor Head Closure Studs." The applicant stated that the program provides for ASME Code Section XI inspections of reactor head closure studs, nuts, and washers for cracking, loss of material, loss of fracture toughness, and coolant leakage from reactor vessel closure stud bolting in an air environment. The applicant stated that the Reactor Head Closure Studs Program is a condition based monitoring program that effectively monitors and detects the applicable aging effects and that the frequency of monitoring is adequate to prevent significant degradation. The applicant further stated that the program is based on examination and inspection requirements specified in the ASME Code Section XI, 1998 Edition, including 2000 Addenda, and preventive measures described in NRC Regulatory Guide (RG) 1.65, "Materials and Inspection for Reactor Vessel Closure Studs." The applicant also stated that: (1) the program uses visual and volumetric examinations in accordance with ASME Code Section XI, (2) the applicable edition of the ASME Code does not require surface examinations of the studs, and (3) surface examinations of the reactor head closure studs are not performed. The applicant stated that the extent and schedule for examining and testing the reactor head closure studs, nuts, and washers are as specified in ASME Code Section XI, Table IWB-2500-1 for Examination Category B-G-1 components "Pressure Retaining Bolting Greater than 2 Inches in Diameter."

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M3. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M3, with the exception of the "detection of aging effects" program element. For this program element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

In GALL AMP XI.M3, the "detection of aging effects" program element states that Examination Category B-G-1 for pressure-retaining bolting greater than 2 inches in diameter in reactor vessels specifies both a surface and a volumetric examination of the studs when they are removed from the reactor vessel flange. In its review of the applicant's "detection of aging effects" program element, the staff noted that the applicant performs a volumetric (not volumetric and surface) examination of reactor head closure studs when they are removed from the reactor vessel flange. The staff also noted that in the "Program Description" subsection of LRA Section B.2.1.3, the applicant stated that the program provides inspections of reactor head closure studs, nuts, and washers for cracking, loss of material, loss of fracture toughness, and coolant leakage from reactor vessel closure stud bolting. The staff further noted that loss of fracture toughness is not addressed as an aging effect in GALL AMP XI.M3.

In RAI B.2.1.3-01, dated June 10, 2010, the staff requested that the applicant explain why implementation of only volumetric examinations, rather than volumetric and surface examinations, for removed closure studs was not identified as an exception to the recommendations in the GALL Report and justify how the use of only volumetric inspections for these components will provide adequate detection of aging effects during the period of extended operation. The staff also requested that the applicant clarify why the loss of fracture toughness is listed as an aging effect managed by the Reactor Head Closure Studs Program.

The applicant's July 8, 2010, response stated that the GALL Report program description states that the ISI requirements are in conformance with the 2001 Edition of the ASME Code Section XI, through the 2003 Addenda. The applicant also stated that the 2001 Edition of the ASME Code Section XI, through the 2003 Addenda, does not require surface examinations of the reactor head closure studs when removed. The applicant further stated that similarly, the Salem Units 1 and 2 ISI program plans, which incorporate the requirements of the ASME Code Section XI 1998 Edition through 2000 Addenda, also do not require surface examinations of the reactor head closure studs when removed, but instead allow either a volumetric or a surface examination. The applicant stated that Salem will continue to satisfy the examination requirements of ASME Code Section XI, Table IWB 2500-1 for the reactor head closure studs, in place and removed. In addition, the applicant indicated that the volumetric examination (only) of the reactor head closure studs when removed is adequate because such an examination is consistent both with applicable ASME Code Section XI requirements and with alternate inspection requirements described in RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," Revision 1, dated April 2010.

The applicant also stated that LRA Appendix B, Section B.2.1.3 inadvertently states that a loss of fracture toughness is an aging effect managed by the Reactor Head Closure Studs Program. The applicant revised LRA Section B.2.1.3 to delete the reference to the loss of fracture toughness as an aging effect managed by the Reactor Head Closure Studs Program.

In its review, the staff finds the applicant's change to LRA Section B.2.1.3 acceptable because it clarified that loss of fracture toughness is not an aging effect and, as revised, the aging effects managed by the Reactor Head Closure Studs Program are consistent with the GALL Report. The staff also finds the applicant's justification for using only volumetric examinations acceptable because the applicable editions and addenda of the ASME Code Section XI allow surface or volumetric examinations, and the staff finds that volumetric examinations, alone, are adequate to detect cracking as documented in the latest revision of RG 1.65. On this basis, the staff finds that the applicant's response resolves all issues described in RAI B.2.1.3-01.

Based on its audit and review of the applicant's response to RAI B.2.1.3-01, the staff finds that elements one through six of the applicant's Reactor Head Closure Studs Program are consistent with the corresponding program elements of GALL AMP XI.M3 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.3 summarizes operating experience related to the Reactor Head Closure Studs Program. The applicant stated that its Reactor Head Closure Studs Program has provisions regarding inspection techniques and evaluation, material specifications, corrosion prevention, and other aspects of reactor pressure vessel (RPV) head stud cracking. In the LRA, the applicant provided several examples of its operating experience. For Salem Unit 1, the applicant stated that the Reactor Head Closure Studs Program performed ultrasonic testing (UT) and visual testing (VT-1) examinations of selected reactor head closure studs, nuts, and washers during the fall 2002, fall 2005, and fall 2008 refueling outages with no recordable indications found. For Salem Unit 2, the applicant stated that the Reactor Head Closure Studs Program performed UT and VT-1 examinations of selected reactor head closure studs, nuts, and washers during the spring 2005, fall 2006, and spring 2008 refueling outages with no recordable indications found. The applicant also stated that the operating experience of the Reactor Head Closure Studs Program shows there are no signs of age-related degradation and that since no age-related degraded conditions have existed, no investigations and corrective actions have been required. The applicant further stated that historically, inspections have found the reactor studs, nuts, and washers to be in satisfactory condition and that no studs, nuts, or washers have ever been replaced or repaired as a result of age-related conditions.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant-specific operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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 of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.3 provides the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also noted that in LRA Section A.5, the applicant adequately committed (Commitment No. 3) to ongoing implementation of the existing Reactor Head Closure Studs Program for managing the aging effects of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Reactor Head Closure Studs Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 Boric Acid Corrosion

Summary of Technical Information in the Application. LRA Section B.2.1.4 describes the existing Boric Acid Corrosion Program as consistent with the program elements in GALL AMP XI.M10, “Boric Acid Corrosion.” The applicant stated that the program identifies, inspects, examines, and evaluates leakage, initiates corrective actions, and relies, in part, on implementation of the recommendations provided in NRC Generic Letter (GL) 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants.” The applicant also stated that this program manages loss of material, delamination of coatings, and corrosion of electrical connector contact surfaces exposed to air with borated water leakage. The applicant further stated that borated water leakage from components outside the scope of the program established in response to GL 88-05 may affect SSCs that are subject to an AMR; therefore, the scope of this program includes all components that contain borated water and are in proximity of SSCs subject to an AMR, including systems and structures inside the containment building, auxiliary building, spent fuel building, and inner penetration area.

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

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.M10. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M10. Based on its audit, the staff finds that elements one through six of the applicant’s Boric Acid Corrosion Program are consistent with the corresponding program elements of GALL AMP XI.M10 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.4 summarizes operating experience related to the Boric Acid Corrosion Program. The applicant provided four examples of operating experience. In one instance of operating experience, the applicant described the engineering analysis conducted in response to detected boric acid crystalline deposits. The applicant stated that the source of the deposits was traced to pinhole leaks at a location above the observed deposits. The applicant also described the resultant corrective action that included the replacement of analogous hardware that the applicant considered susceptible to similar degradation. In other operating experience provided in the LRA, the applicant presented instances of engineering evaluations that led to appropriate component replacements in response to leakage detected during the program’s inspections.

The applicant's operating experience indicated its cognizance of GL 88-05, Bulletin 2002-01, and Information Notice (IN) 2003-02, which reported issues in nuclear power plants associated with boric acid leakage and subsequent corrosion reactions and provided details on engineering analyses and corrective actions taken in response to detected leakage of boric acid. In one recorded instance, the applicant described its process in which direct measurements and engineering analyses were provided to establish a quantified assessment of corrosion effects on components contacted by boric acid due to leakage. In another recorded instance of operating experience, the applicant described an instance where a service water leak led to deterioration of a stainless steel tube which resulted in boric acid leakage. The applicant stated that the detection limits for chlorides were revised as part of an improvement in plant leak detection methods.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.4 provides the UFSAR supplement for the Boric Acid Corrosion Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, 3.4-2, 3.5-2, and 3.6-2. The staff also notes that the applicant committed (Commitment No. 4) to ongoing implementation of the existing Boric Acid Corrosion Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Boric Acid Corrosion Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors

Summary of Technical Information in the Application. LRA Section B.2.1.5 describes the existing Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program (hereafter, Nickel-Alloy Head Penetration Program) as consistent with GALL AMP XI.M11A, “Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors.” The applicant stated that the program manages cracking due to primary water stress-corrosion cracking (PWSCC) in a reactor coolant environment and inspects for boric acid leakage residue on nickel-alloy pressure vessel head penetration nozzles. The applicant also stated that the program includes the reactor vessel closure head, the upper vessel head penetration nozzles, and associated J groove welds. The applicant further stated that cracking was mitigated through control of water chemistry. The applicant also stated that the aging effects of cracking and loss of material were managed through a combination of surface and volumetric inspection techniques as described in ASME Code Case N-729-1 as modified by 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6).

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 AMP XI.M11A. The staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M11A. Based on its review, the staff finds that elements one through six of the applicant’s Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program are consistent with the corresponding program elements of GALL AMP XI.M11A and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.5 summarizes operating experience related to the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program. In this section, the applicant stated that it has not detected PWSCC in any of the upper vessel head penetration nozzles. The applicant also stated that it preemptively replaced both the Unit 1 and Unit 2 heads in 2005 with heads constructed from PWSCC resistant material (Alloys 690 and 52). As evidence of the effectiveness of its AMP, the applicant provided three examples. Each of these examples addresses the attentiveness of the applicant, through the application of its AMP, to the potential for, and mitigation of, PWSCC. The applicant cited: (1) its preemptive replacement of the heads for Units 1 and 2, (2) its work with the fabricator of the heads to identify and reduce indications observed in the new heads, and (3) its prompt incorporation in its AMP of changes to its ISI program for its upper head as directed by the revision to NRC Order EA-03-009 and ASME Code Case N-729-1.

The staff reviewed operating experience information which is contained in the application and in the GALL Report and which has occurred since the publication of the GALL Report, to determine whether all the applicable aging effects and industry and plant-specific operating experience were considered by the applicant and whether the proposed AMP is sufficient to address this operating experience. 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 GALL Report, and recent industry operating experience, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate preventive 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.2.1.5 provides the UFSAR supplement for the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.2-2. The staff also notes that the applicant committed (Commitment No. 5) to ongoing implementation of the existing Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program, the staff finds that program elements 1–6 and 10 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).

3.0.3.1.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Summary of Technical Information in the Application. LRA Section B.2.1.6 describes the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program as a new program that includes condition monitoring activities to provide assurance that RCS CASS components susceptible to thermal aging embrittlement meet the intended functions. The RCS CASS components are maintained by inspecting and evaluating the extent of thermal aging embrittlement in accordance with the requirements of ASME Code Section XI, 1998 Edition, through the 2000 Addenda. The applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program at Salem Units 1 and 2 is augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, which monitors the aging effect of the loss of fracture toughness due to thermal aging embrittlement of CASS components.

The applicant stated that the program elements for this new AMP are consistent with the program element criteria recommended in GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," without exception or enhancement.

Staff Evaluation. GALL AMP XI.M12 establishes the criteria for determining whether a supplemental flaw tolerance assessment or volumetric or enhanced VT-1 inspection techniques should be credited to manage reduction of fracture toughness due to thermal aging embrittlement in RCS CASS piping, piping components, or piping elements.

The letter from Christopher I. Grimes of the NRC to Douglas J. Walters of the NEI, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," May 19, 2000, provides additional criteria for determining whether a particular CASS material is susceptible to thermal aging embrittlement and describes aging management strategies for these materials. The guidance in GALL AMP XI.M12 references the additional guidelines provided in the May 19, 2000, letter. The staff reviewed the information in LRA Section B.2.1.6 and the applicant's response to the staff's RAI questions dated June 3, 2010. The staff noted that the program elements for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program were consistent with the program element criteria recommended in GALL AMP XI.M12. However, the staff asked the applicant to clarify certain issues in the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, as follows.

By letter dated May 14, 2010, the staff issued RAI B.2.1.6-1, requesting that the applicant identify the scope of the subject CASS AMP and provide the schedule of its implementation. By letter dated June 3, 2010, the applicant responded that the scope of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program (also referred to as the CASS AMP or CASS program) is limited to the Salem RCS piping. Specifically, the only components that are potentially susceptible to thermal aging embrittlement within the scope of the new CASS program are the CASS elbows within the RCS primary loop piping (i.e., the hot legs, crossover legs, and cold legs). The applicant evaluated these CASS elbows for aging management as component type "Reactor Coolant Pressure Boundary Components" in LRA Table 3.1.2-1. The applicant stated that there are no CASS vessels, pumps, or valves covered under the CASS program. The applicant also stated that the Salem reactor vessel is constructed of low-alloy steel with a stainless steel cladding. The applicant further stated that the aging effects associated with the CASS pressurized water reactor (PWR) vessel internals are managed by the PWR Vessel Internals Program as shown in LRA Appendix B, Section B.2.1.7. The applicant stated that the aging effects associated with the CASS reactor coolant pump (RCP) casings and CASS valves are managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as shown in LRA Appendix B, Section B.2.1.1; Water Chemistry Program as shown in LRA Appendix B, Section B.2.1.2; and time-limited aging analysis (TLAA). The staff finds that the applicant has clearly defined the scope of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program and its response is acceptable.

The applicant stated that the CASS program will be implemented for Salem Unit 1 before the end of its 24th refueling outage, tentatively scheduled for April 2016. For Salem Unit 2, the CASS program will be implemented before the end of its 24th refueling outage, tentatively scheduled for April 2020. The period of extended operation starts on August 13, 2016, and April 18, 2020, for Salem Units 1 and 2, respectively. The staff finds that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will be implemented before the commencement of the period of extended operation and, therefore, is acceptable.

The applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program at Salem is augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. The staff notes that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program requires inspection of only a limited number of welds in a piping system once every 10 years. The staff stated that UT is not reliable and not yet qualified in detecting flaws in CASS components. The staff also stated that surface and visual examinations detect flaws only after degradation has occurred. It is not clear to the staff how the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program can detect thermal aging embrittlement in the CASS components in time to prevent component degradation. In RAI B.2.1.6-2, the staff requested that the applicant discuss exactly how the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is augmented and enhanced as a result of implementing the CASS AMP.

By letter dated June 3, 2010, the applicant responded that currently, the welds associated with the CASS elbows are already within the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, specifically the RI-ISI program covering all Class 1 and Class 2 welds. Although these welds are considered Risk Category 4 by the RI-ISI program, they are not selected for examination due to the inability of existing volumetric examination techniques to examine the welds due to the CASS composition of the elbows. The new CASS program does not change the frequency of examination of these welds because they are still within the RI-ISI program.

The applicant stated that since a qualified volumetric examination technique does not currently exist for CASS materials, Salem performed a component-specific flaw tolerance evaluation for the CASS elbows, where a portion of the CASS elbow comprises the weld area subject to examination. The flaw tolerance evaluation concluded that the CASS elbows within the Salem RCS primary loop are tolerant of large flaws through the period of extended operation.

The applicant stated that it will manage the aging of the CASS components using the flaw tolerance evaluation. The applicant further stated that if a volumetric examination technique is qualified in the future, the RI-ISI program at that time will determine whether: (1) the CASS elbow welds will be examined by the qualified volumetric technique in accordance with 10 CFR 50.55a requirements or (2) if the flaw tolerance evaluation will continue to be used for aging management of the CASS components. There are no new license renewal enhancements to the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as a result of implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.

The staff finds that the use of the flaw tolerance evaluation to monitor the structural integrity of the CASS components is consistent with the guidance in GALL AMP XI.M12 and, therefore, its use is acceptable. The staff notes that it has sponsored a research and development program at the Pacific Northwest National Laboratory on the qualification of UT of CASS material as shown in NUREG/CR-6933, “Assessment of Crack Detection in Heavy-Walled Cast Stainless Steel Piping Welds Using Advanced Low-Frequency Ultrasonic Methods.” In addition, the staff is working with the ASME and nuclear industry to develop an ASME Code case for the UT of CASS material. In the near future, licensees should be able to perform ultrasonic examination of CASS material using the ASME Code case.

In RAI B.2.1.6-3, the staff asked the applicant to describe the flaw tolerance evaluation and discuss how the flaw tolerance evaluation will be implemented during the period of extended operation to ensure the structural integrity of the CASS components. The staff also asked the applicant to discuss how the CASS components will be inspected under the RI-ISI program at Salem considering the requirements of the CASS AMP (e.g., whether the CASS AMP will increase the inspection frequency of the CASS components in the RI-ISI program and whether thermal aging embrittlement will be a degradation mechanism considered in the RI-ISI program).

In its response dated June 3, 2010, the applicant stated that thermal aging embrittlement of the CASS components will be managed by the Salem component-specific flaw tolerance evaluation, since a qualified volumetric examination technique does not currently exist for CASS materials. The flaw tolerance evaluation has been incorporated into the Salem design basis.

As a result of implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, the RI-ISI program will be revised to use the flaw tolerance evaluation if any of the CASS elbow welds are selected for examination. The flaw tolerance evaluation concludes that the CASS elbows are tolerant of large flaws, where a very large flaw (e.g., 31 percent through-wall with an aspect ratio of 6) would remain within the ASME Code Section XI acceptance criteria throughout the period of extended operation, thereby ensuring the structural integrity of the CASS components.

The applicant noted that performance of a flaw tolerance evaluation is identified as one acceptable approach for managing the aging effect of thermal aging embrittlement of CASS components as suggested in GALL AMP XI.M12. The objective of the flaw tolerance evaluation was to determine whether the CASS components are tolerant of large flaws (i.e., an initial flaw of a large size can remain within the ASME Code Section XI acceptance criteria for a plant operation life of 60 years). To determine whether the CASS elbows are tolerant of large flaws, the applicant calculated acceptable maximum initial flaw sizes for limiting cases by determining the maximum allowable final flaw based on ASME Code Section XI acceptance criteria and subtracting the fatigue crack growth over incremental plant operation durations. The results of the flaw tolerance evaluation are presented in curves of maximum allowable initial flaw sizes as a function of aspect ratios. The Salem component-specific flaw tolerance evaluation demonstrated that the susceptible CASS components are tolerant of large flaws. The following provides a detailed description of the Salem component-specific flaw tolerance evaluation.

The NRC Grimes letter dated May 19, 2000, provides the screening criteria for determining the CASS components susceptible to thermal aging embrittlement. The CASS components that were considered susceptible to thermal aging embrittlement were the CASS elbows installed in the Salem Units 1 and 2 RCS primary loop. All of the CASS elbows within the primary loop: (1) were fabricated of SA351 CF8M, (2) were static-cast, (3) had a molybdenum content exceeding 2 percent, and (4) had varying ferrite levels from 8.81 percent up to 22.17 percent.

The component-specific flaw tolerance evaluation, Westinghouse Proprietary Document: LTR-PAFM-09-60, Revision 0, “Flaw Tolerance Evaluation for Susceptible CASS Reactor Coolant Piping Components in Salem Units 1 and 2,” used the flaw evaluation guidelines provided in the Grimes letter. Since none of the CASS elbows had ferrite greater than 25 percent, ASME Code Section XI, paragraph IWB-3640 flaw evaluation procedures were used in the flaw tolerance evaluation preparation. For the purposes of the Salem component-specific flaw tolerance evaluation, the code of record for Salem, ASME Code Section XI, 1998 Edition, including the 2000 Addenda, was used.

The applicant determined the allowable flaw size at the end of the inspection/evaluation periods representing 10, 20, 30, and 40 years of service. These years of service are based on the 40-year transient design cycles. The applicant reviewed LRA Table 4.3.1-3, “Design Transients and 60-Year Projections for NSSS Class A and Class 1 Components at Salem Unit 1,” and LRA Table 4.3.1-4, “Design Transients and 60-Year Projections for NSSS Class A and Class 1 Components at Salem Unit 2,” and concluded that the transient cycles projected for 60 years of operation were bounded by the corresponding 40-year transient design cycles. Therefore, the inspection/evaluation periods are valid through the period of extended operation. The applicant stated that the flaw tolerance evaluation results correspond to 15, 30, 45, and 60 years of plant operation.

In applying the ASME Code Section XI acceptance criteria, the end-of-evaluation allowable flaw size is defined as the flaw size to which the detected or postulated flaw is allowed to grow until the next inspection period. The end-of-evaluation period flaw size is a function of stresses, crack geometry, and material properties. The end-of-evaluation period is defined as the service life from the time of flaw detection to the time of the next scheduled examination or planned repair, or at the end of life for the component. The flaw tolerance evaluation determined the allowable flaw sizes for the appropriate limiting load conditions. The first of these allowable flaw sizes was calculated using stresses from the governing normal, upset, and test conditions. The second of these allowable flaw sizes was calculated based on stresses for the governing emergency and faulted conditions. The most limiting allowable flaw size determined for the normal, upset, emergency, test, and faulted conditions was used as the maximum end-of-evaluation period flaw size.

The applicant stated that the end-of-evaluation period flaw sizes of IWB-3640 in ASME Code Section XI, for the high toughness base materials, were determined based on the assumption that plastic collapse would be achieved and would be the dominant mode of failure. However, the applicant also stated that due to the reduced toughness of the susceptible CASS material resulting from thermal aging embrittlement, it is possible that crack extension and unstable ductile tearing could occur and be the dominant mode of failure. The applicant stated that to account for this effect, the Grimes letter requires that the “Z factors” for submerged arc welds given in ASME Code Section XI, Appendix C be used as a multiplier to increase the limiting loads used in determining the maximum end-of-evaluation period allowable flaw size. The applicant further stated that this is supported by the results from the Argonne National Laboratory Research Program indicating that the lower-bound fracture toughness of thermally-aged cast stainless steel is similar to that of submerged arc welds, as stated in the Grimes letter.

The applicant analyzed fatigue flaw (crack) growth considering thermal, deadweight, seismic, pressure, and thermal transient stresses and residual stresses. The 40-year design transient cycles, which bound the corresponding 60-year projected transient cycles, were considered in the fatigue crack growth analyses. The applicant used welding residual stress values from the technical article, “Evaluation of Flaws in Austenitic Steel Piping-Section XI Task Group for Piping Flaw Evaluation,” Transactions of ASME, Journal of Pressure Vessel Technology, Volume 108, August 1986, pp. 352–366, in the fatigue crack growth analysis. In addition, the applicant considered residual stresses resulting from mechanical stress improvement procedures (MSIP) applied at the reactor vessel nozzle-to-safe end dissimilar metal weld regions for Salem Units 1 and 2 reactor vessel inlet (cold leg) nozzle elbows to obtain the most limiting fatigue crack growth results. The residual stresses by MSIP are added algebraically (algebraic sum method) to the thermal, deadweight, seismic, pressure, and thermal transient stresses in the fatigue crack growth analysis. Although Salem Unit 2 has not completed MSIP on its cold leg (inlet) reactor vessel nozzle-to-safe end welds, the applicant nevertheless accounted for residual stresses, thereby adding conservatism to the flaw tolerance evaluation.

The staff notes that the purpose of the MSIP is to alter the residual stress pattern in the dissimilar metal weld, placing the inner part of the weld in compression, thus inhibiting crack initiation. If cracks are present in the weld, the residual stress pattern is more complex. If cracks are shallow, the MSIP will probably prevent further crack growth, as long as the residual stress remains favorable (i.e., compressive). For deeper cracks, particularly those penetrating deeper than halfway through the weld wall, the crack tip is likely to experience a general tensile stress field after MSIP, which may cause the crack to propagate in the weld. NUREG-0313, Revision 2, “Technical Report on Material Selection and Processing Guidelines for BWR

Coolant Pressure Boundary Piping," provides limitations on the MSIP application based on the crack size. The CASS elbow located next to the dissimilar metal weld may experience residual (tensile) stresses as a result of the MSIP of the dissimilar metal weld. The staff finds acceptable that the applicant considered the impact (residual tensile stresses) of the MSIP in the flaw tolerance evaluation for the CASS elbow.

The fatigue crack growth analysis procedure involves postulating an initial flaw (crack) at the susceptible component and predicting the flaw growth due to an imposed series of loading transients. The input required for a fatigue crack growth analysis is information necessary to calculate the parameter ΔK_I (range of crack tip stress intensity factor), which depends on the geometry of the crack, its surrounding structure, and the range of applied stresses in the crack area.

The applicant derived the stress intensity factors for semi-elliptical inside surface axial flaws using expressions found in the following technical literatures: (1) Raju, I.S. and Newman, J.C., "Stress Intensity Factor Influence Coefficients for Internal and External Surface Cracks in Cylindrical Vessels," ASME Publication Pressure Vessel and Piping, Volume 58, 1982, pp. 37-48 and (2) Mettu, S.R. et al, NASA Lyndon B. Johnson Space Center Report No. NASA-TM-111707, "Stress Intensity Factors for Part-through Surface Cracks in Hollow Cylinders," in Structures and Mechanics Division, July 1992. Similar calculations were performed for inside surface circumferential flaws based on the technical resource S. Chapuliot et al, "Stress Intensity Factors for Internal Circumferential Cracks in Tubes over a Wide Range of Radius over Thickness Ratios," ASME Pressure Vessel and Piping Volume 365, 1998.

After ΔK_I was calculated, the applicant calculated crack growth due to a particular stress cycle using the applicable crack growth reference curves for stainless steel in an air environment from ASME Code Section XI, Appendix C with an environmental factor of 2.0 to account for the PWR water environment. The factor of 2.0 is based on the following technical article: "Evaluation of Flaws in Austenitic Steel Piping-Section XI Task Group for Piping Flaw Evaluation," Transactions of ASME, Journal of Pressure Vessel Technology, Volume 108, August 1986, pp. 352–366. The incremental fatigue crack growth was added to the postulated initial crack size, and the analysis proceeded to the next cycle or transient. The fatigue crack growth calculation was continued in this manner until all the 40-year design transients for the design plant life were analyzed.

The applicant used bounding material properties, geometry, and stresses in each leg (hot, cold, and crossover) of the Salem Units 1 and 2 RCS primary loops. For a particular flaw shape and configuration, the maximum acceptable initial flaw size for a given service life (i.e., 10, 20, 30, 40 years), based on the original 40-year transient design cycles which bound the 60 years of plant operation, was determined by subtracting the corresponding fatigue crack growth from the end-of-evaluation period allowable flaw size. The maximum acceptable initial flaw sizes for various flaw configurations and aspect ratios are provided in the flaw tolerance evaluation.

The applicant stated that for example, the results of the flaw tolerance evaluation for a flaw aspect ratio of 6 and plant operation duration of 60 years are shown in Table 1 below. As shown in Table 1 below, the maximum acceptable initial circumferential flaw depth is 31 percent through-wall for the susceptible hot leg elbows, which is the most limiting case.

Considering the wall thickness near the hot leg elbow weld of 2.50 inches, a circumferential flaw initiated at original plant startup, with a depth of up to 31 percent of the wall thickness, equating to 0.78 inches (0.31 x 2.50 inches) in depth, and having a length up to 4.68 inches, based on the aspect ratio of 6 (0.78 inches x 6 = 4.68 inches) would remain within the acceptance criteria of IWB-3640 for 60 years of plant service life. For all other flaw configurations and susceptible elbow locations tabulated in Table 1, the maximum acceptable initial flaw depths are larger than this most-limiting case. Therefore, even with thermal aging embrittlement, the Salem component-specific flaw tolerance evaluation concludes that the susceptible CASS elbows are tolerant of large flaws.

Table 1
Acceptable Initial Flaw Sizes (% Through-wall Thickness) for Salem Susceptible CASS Elbow Locations (Aspect Ratio = 6, for a Plant Operation Duration of 60 years)

Susceptible CASS Limited Elbow Locations	Axial Flaw		Circumferential Flaw	
	Acceptable Initial Flaw Size	Allowable Final Flaw Size	Acceptable Initial Flaw Size	Allowable Final Flaw Size
Hot Leg (Outlet)	43.4%	49%	31%	50%
Crossover Leg	50.0%	59%	38.2%	62%
Cold Leg (Inlet)	45.2%	52%	42.8%	75%

The staff finds that the applicant's flaw tolerance evaluation methodology is consistent with ASME Code Section XI, Appendix C and with the program elements in GALL AMP XI.M12 which references the guidance in the NRC (Grimes) letter dated May 19, 2000. Therefore, the flaw tolerance evaluation is acceptable.

On April 15, 2010, the staff audited the Westinghouse report "Flaw Tolerance Evaluation for susceptible CASS Reactor Coolant Piping Components in Salem Units 1 and 2," LTR-PAFM-09-60, in the Westinghouse Satellite Office in Rockville, Maryland. This audit is part of the staff's review of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program to verify the acceptability of the flaw tolerance evaluation. As part of the audit, the applicant provided responses to the staff's RAI regarding the subject flaw tolerance evaluation.

The Salem plant-specific flaw tolerance evaluation showed residual stresses at the reactor vessel inlet nozzle safe end-to-cold leg elbow weld regions as a result of the MSIP. In RAI B.2.1.6-7, the staff requested that the applicant discuss how the residual stresses are factored in the allowable flaw size calculation for the cold leg elbow and to identify the CASS elbows in the piping systems covered under the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program in each Unit that are affected by the MSIP.

In its response dated June 3, 2010, the applicant stated that MSIP was implemented for the Salem Unit 1 reactor vessel inlet nozzle safe end-to-cold leg elbow weld regions. MSIP has not been implemented for the Salem Unit 2 reactor vessel inlet nozzle safe end-to-cold leg elbow weld regions.

To obtain the limiting fatigue crack growth results, the applicant considered the effects of residual stresses due to MSIP for all eight cold leg elbows in Salem Units 1 and 2, as well as those from the technical article "Evaluation of Flaws in Austenitic Steel Piping-Section XI Task

Group for Piping Flaw Evaluation," Transactions of ASME, Journal of Pressure Vessel Technology, Volume 108, August 1986, pp. 352–366. Although Salem Unit 2 has not completed MSIP on its cold leg (inlet) reactor vessel nozzle-to-safe end dissimilar metal welds, the effects of MSIP residual stresses were conservatively accounted for in the flaw tolerance evaluation. The residual stresses due to MSIP were added algebraically (algebraic sum method) to the pressure, deadweight, seismic, and thermal transient stresses in the fatigue crack growth analysis as discussed above.

The resulting fatigue crack growth was then used to determine the maximum allowable initial flaw size for a given plant operation. The maximum allowable initial flaw size is determined by the duration of plant operations from the maximum allowable end-of-evaluation period flaw size which was determined in accordance with the flaw evaluation and acceptance criteria in the ASME Code Section XI.

The Salem Unit 1 cold leg elbows are not susceptible to thermal aging embrittlement since their ferrite content is less than 14 percent. One of the cold leg elbows on Salem Unit 2 has ferrite content less than 14 percent with the remaining three legs between 14 percent and 17 percent. Although Salem Unit 2 has not yet implemented MSIP on the reactor vessel inlet nozzle-to-safe end dissimilar metal welds, the projected residual stresses associated with MSIP were conservatively addressed in the flaw tolerance evaluation for Salem Unit 2. The applicant stated that the four CASS elbows welded to the Salem Unit 2 reactor vessel inlet nozzle safe ends (cold legs) are also affected by MSIP.

The staff finds that the residual stresses due to MSIP were added algebraically to the other stresses in the flaw tolerance evaluation and that the applicant has identified the CASS components that may be susceptible to thermal aging embrittlement based on their ferrite content. Therefore, the staff finds that the applicant has satisfactorily addressed the issue.

Figures 6-1 to 6-6 in the Salem flaw tolerance evaluation show flaw tolerance curves are applicable to 40 years, but not 60 years. In RAI B.2.1.6-8, the staff requested that the applicant explain why the flaw tolerance curves for 60 years were not generated. By letter dated June 3, 2010, the applicant responded that the flaw tolerance curves presented in Figures 6-1 to 6-6 of the Salem component-specific flaw tolerance evaluation were generated based on Salem's 40-year thermal transient design cycles, which are listed in LRA Table 4.3.1-2, "Design Transient Cycles for NSSS Class A and Class 1 Components at Salem Units 1 and 2." As part of the LRA, the number of thermal transient cycles were projected for 60 years of operation and are shown in LRA Tables 4.3.1-3, "Design Transients and 60-Year Projections for NSSS Class A and Class 1 Components at Salem Unit 1," and 4.3.1-4, "Design Transients and 60-Year Projections for NSSS Class A and Class 1 Components at Salem Unit 2," for Salem Units 1 and 2, respectively.

LRA Section 4.3.1 states that the thermal transient cycles projected for 60 years are bounded by the original 40-year thermal transient design cycles. Therefore, the flaw tolerance curves presented in Figures 6-1 to 6-6 of the flaw tolerance evaluation, which are based on the original 40-year thermal transient design cycles, are valid for up to 60 years of plant operation.

The staff finds that the Salem flaw tolerance evaluation used the 40-year transient cycles; however, the 40-year transient cycles bound the 60-year project cycles. Therefore, the staff finds this acceptable.

In RAI B.2.1.6-9, the staff requested that the applicant discuss how an actual flaw would be dispositioned if detected in a CASS elbow exceeding the acceptable initial flaw size. By letter dated June 3, 2010, the applicant responded that if Salem uses a qualified volumetric technique for examining the CASS elbows, and if a flaw is detected that exceeds the acceptable initial flaw size, this finding will be documented in the corrective action program and the flaw would be dispositioned by performing an additional flaw evaluation based on the as-found flaw configuration in accordance with the evaluation procedure and acceptance criteria in ASME Code Section XI, paragraph IWB-3640. The additional flaw evaluation results will be used to determine an appropriate inspection frequency. If required by the flaw evaluation, additional corrective actions, including such options as repair or replacement, would be specified in accordance with the corrective action program.

The staff finds that the applicant will disposition detected flaws in the CASS components in accordance with ASME Code Section XI, paragraph IWB-3640, therefore, it is acceptable.

In RAI B.2.1.6-10, the staff requested that the applicant describe in detail how the allowable flaw sizes were calculated. By letter dated June 3, 2010, the applicant responded that Table 6-1 of the Salem component-specific flaw tolerance evaluation provides both the maximum allowable (acceptable) initial and final flaw sizes for susceptible CASS elbows in the hot leg, crossover leg, and cold leg locations. These flaw sizes are listed as percent through-wall thickness, based on an aspect ratio (ratio of flaw length to flaw depth for surface flaw) of 6, which is consistent with the assumed aspect ratio in the 1998 Edition of ASME Code Section XI, Article L-3000, and a service life of 40 years. The staff has not yet approved the ASME Code Section XI, Appendix L where Article L-3000 is referenced. However, the applicant's use of aspect ratio 6 in this particular case is not objectionable.

The maximum end-of-evaluation period (final) flaw size was first determined in accordance with the flaw evaluation and acceptance criteria given in ASME Code Section XI, paragraph IWB-3640, which is consistent with the flaw evaluation methodology presented in the NRC Grimes letter. ASME Code Section XI, Appendix C provides the limit load equations and Z factors for the IWB-3640 flaw evaluation. A fatigue crack growth evaluation was performed to determine fatigue crack growth for various plant operation durations (i.e., 10, 20, 30, and 40 years) based on the Salem-specific 40-year design thermal transients cycles.

The maximum allowable initial flaw size for a given plant operation duration (i.e., 10, 20, 30, or 40 years) was then calculated by subtracting the fatigue crack growth determined for that plant operation duration from the maximum allowable end-of-evaluation period (final) flaw size.

The staff finds that the applicant used appropriate methodology in the ASME Code Section XI and in the NRC Grimes letter to obtain the allowable crack size. Therefore, the staff finds that the applicant has satisfactorily addressed the issue.

In RAI B.2.1.6-11, the staff requested that the applicant: (1) confirm that for the fatigue crack growth calculation, the flaw growth rate for the PWR water environment was used; and (2) to discuss whether the flaw growth rate used in the calculation is consistent with the flaw growth rate in the ASME Code Section XI, Appendix C.

In its response dated June 3, 2010, the applicant stated that the fatigue crack growth rate for the PWR water environment was used in the fatigue crack growth calculation. The fatigue crack growth rate curves used in the flaw tolerance evaluation were consistent with the curves in the ASME Code Section XI, Appendix C; however, the crack growth rate curves were modified to account for the PWR water environment. The fatigue crack growth rate curves contained in the ASME Code Section XI, Appendix C are for austenitic stainless steel in an air environment. The Salem flaw tolerance evaluation accounted for the PWR water environment by applying an environmental factor of 2 to the air environment curve in ASME Code Section XI, Appendix C. The environmental factor of 2 is based on the technical article “Evaluation of Flaws in Austenitic Steel Piping-Section XI Task Group for Piping Flaw Evaluation,” Transactions of ASME, Journal of Pressure Vessel Technology, Volume 108, August 1986, pp. 352–366.

The staff finds that the applicant has used an appropriate fatigue crack growth rate curve with an environmental factor of 2. This multiplier is consistent with the staff position and is acceptable.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program references the requirements of ASME Code Case N-481, “Alternate Examination Requirements for Cast Austenitic Pump Casings,” for the inspection of pump casings and valve bodies as suggested in GALL AMP XI.M12. The NRC approved ASME Code Case N-481 in RG 1.147, Revision 14. However, the ASME annulled Code Case N-481 on March 28, 2004, after the requirements of Code Case N-481 were incorporated into the ASME Code Section XI. Subsequently, the NRC also annulled the code case as indicated in RG 1.147, Revision 15. In RAI B.2.1.6-4, the staff requested that the applicant justify the use of Code Case N-481 or propose alternative examinations for pump casings and valve bodies as part of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.

By letter dated June 3, 2010, the applicant responded that the “Program Description” of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program incorrectly referenced the alternative inspection requirements of ASME Code Case N-481 as being adequate for all pump casings and valve bodies. The Class 1 pump casings and valve bodies are within scope for aging management under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as shown in LRA Appendix B, Section B.2.1.1; the Water Chemistry Program as shown in LRA Appendix B, Section B.2.1.2; and the TLAA. The correct reference for inspection requirements of pump casings and valve bodies is found in the ASME Code Section XI, Table IWB-2500-1, Categories B-L-2 and B-M-2 for pump casing and valve body inspections, respectively. Therefore, no alternative examinations are required for the CASS pump casings and valve bodies under the CASS program, and the ASME Code Case N-481 will not be used for these components.

As a result of the incorrect reference to ASME Code Case N-481, the applicant revised LRA Appendix A, Section A.2.1.6, page A-10, second paragraph. The staff finds that the applicant has deleted the reference to Code Case N-481 in the revised paragraph in LRA Section A.2.1.6. Therefore, the staff finds that the applicant has satisfactorily addressed the issue.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program states that, “…Flaw tolerance evaluation for components with ferrite content up to 25 percent is performed according to IWB-3640 for submerged arc welds (SAW)…” In RAI B.2.1.6-5, the staff requested that the applicant clarify the intent of the above statement and discuss whether the Salem units have CASS components with ferrite content greater than 25 percent.

By letter dated June 3, 2010, the applicant responded that the intent of the statement, “…Flaw tolerance evaluation for components with ferrite content up to 25 percent is performed according to IWB-3640 for submerged arc welds (SAW)…,” is to reiterate the acceptance criteria discussed in GALL AMP XI.M12. If the ferrite content does not exceed 25 percent, the flaw tolerance evaluation would be performed in accordance with the principles associated with the ASME Code Section XI, paragraph IWB-3640 procedures for SAW, disregarding the ASME Code ferrite restriction of 20 percent in IWB-3641(b)(1), in accordance with the NRC Grimes letter.

If the ferrite content for the CASS material was greater than 25 percent, then the flaw tolerance evaluation would have been performed on a case-by-case basis using fracture toughness data. Since the material of the Salem CASS components susceptible to thermal aging embrittlement contains less than 25 percent ferrite, the flaw tolerance evaluation was performed in accordance with IWB-3640 procedures for SAW, disregarding the ferrite ASME Code restriction of 20 percent in IWB-3641(b)(1), in accordance with the NRC Grimes letter.

The applicant clarified further that the CASS components covered under the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program do not have ferrite content values greater than 25 percent. The applicant also stated that the flaw tolerance evaluation, Westinghouse letter, LTR-PAFM-09-60, "Flaw Tolerance Evaluation for Susceptible CASS Reactor Coolant Piping Components in Salem Units 1 and 2," dated July 2009 was prepared for, and is only applicable to, the susceptible CASS components (i.e., elbows) in the CASS program.

The staff finds that the applicant clarified the issue on the ferrite content that the RCS primary loop piping does not have CASS components with ferrite content values greater than 25 percent.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program cites an operating experience of cracking in impeller vanes of RCPs attributed to thermal aging embrittlement. In RAI B.2.1.6-6, the staff requested that the applicant discuss whether the impeller vane degradation is applicable to the Salem units and whether the impeller vanes at Salem have been inspected. By letter dated June 3, 2010, the applicant responded that the operating experience citing impeller vane degradation was initially thought to potentially be due to thermal aging embrittlement. Upon further review, the applicant has determined that the operating experience of the impeller vane degradation is not applicable to the Salem units. The cause of failure associated with the impeller vane operating experience was due to internal shrinkage during the casting process and is not caused by thermal aging embrittlement.

The applicant deleted the reference to the impeller vane in the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. The staff finds it acceptable that the reference to impeller vane cracking is deleted from the CASS program because the cracking of the impeller vanes of RCPs is not related to the thermal aging embrittlement degradation mechanism and is not applicable to the Salem units.

Based on its review, the staff finds that the applicant's aging management basis and program elements in the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program are acceptable because they are consistent with the staff's recommended aging management basis and program elements that are defined in GALL AMP XI.M12.

<u>UFSAR Supplement</u>. LRA Section A.2.1.6 provides the UFSAR supplement for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging of RCS CASS components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). 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 PWR Vessel Internals

Summary of Technical Information in the Application. In LRA Section B.2.1.7, the applicant described its PWR Vessel Internals Program, stating that this new program commits to the following:

(1) participate in the industry programs for investigating and managing aging effects on reactor internals

(2) evaluate and implement the results of the industry programs as applicable to the reactor internals

(3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval

The applicant then concluded the following:

> The new PWR Vessel Internals aging management program will provide reasonable assurance that the changes in dimensions, cracking, loss of fracture toughness, and loss of preload aging effects will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained consistent with the current licensing basis during the period of extended operation.

Staff Evaluation. For RPV internals, the management of postulated aging effects that may occur for PWRs is covered in the following LRA sections:

- Section 3.1.2.2.6, “Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling”
- Section 3.1.2.2.9, “Loss of Preload Due to Stress Relaxation”
- Section 3.1.2.2.12, “Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking (IASCC)”
- Section 3.1.2.2.15, “Changes in Dimensions Due to Void Swelling”

- Section 3.1.2.2.17, "Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking"

No further evaluation is recommended by the GALL Report if the applicant's commitment specified under the Table IV.B2 column heading "Aging Management Program (AMP)" for these RPV internals (or line items) is confirmed as specified below:

No further AMR is necessary if the applicant provides a commitment in the UFSAR supplement to: (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

The above commitment is also stated as a requirement in SRP-LR Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17. By comparing the contents of the PWR Vessel Internals Program with Commitment No. 7 (LRA Table A.5) and with the commitments specified in the SRP-LR and GALL Report Table IV.B2, the staff concludes that the PWR Vessel Internals Program is equivalent to the SRP-LR required commitment for specific PWR RPV internals. Hence, the staff considers the applicant's PWR Vessel Internals Program, at the present form, a means for fulfilling Commitment No. 7, designed solely to meet a key aging management guideline provided in SRP-LR Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17 for specific PWR RPV internals. Due to this unique feature, the staff determined that the 10 evaluation elements for a typical GALL Report AMP do not apply to the applicant's PWR Vessel Internals Program.

In addition to the PWR Vessel Internals Program, the staff verified that LRA Sections 3.1.2.2.12 and 3.1.2.2.17 also require control of water chemistry to mitigate the specific aging mechanism(s) for RPV internals. The staff's evaluation of water chemistry can be found in SER Section 3.0.3.1.2.

The staff noted that the lists of components in LRA Table 3.1.2-3 under the aging effects of LRA Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17 for the RPV internals do not seem to be consistent with the lists of components in GALL Report Table IV.B2, for which the PWR Vessel Internals Program is credited for part or all of the aging management. These seeming inconsistencies are largely due to: (1) the plant-specific features of the RPV internals which contain more components than those listed in GALL Report Table IV.B2 and (2) the applicant's use of several subcomponents to represent a typical component in GALL Report Table IV.B2. SER Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17 contain the staff's resolution of the RAIs related to these inconsistencies.

Based on the staff's review above and the staff's resolution of RAIs related to inconsistencies of component listings between the LRA and the GALL Report, the staff concludes that the PWR Vessel Internals Program, in its present form, is equivalent to Commitment No. 7, which is designed to meet the SRP-LR and GALL Report Table IV.B2 requirements for the RPV internals under the aging mechanisms identified earlier. Hence, working with appropriate AMP(s), as specified in GALL Report Table IV.B2, the PWR Vessel Internals Program is acceptable for management of aging effects listed above for the RPV internals. In the future, the program contents will be replaced by the plant-specific version of the industry program documented in Modification/Rework Package (MRP)-227, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," with the NRC-specified conditions.

The revised PWR Vessel Internals Program will be submitted to the staff for review and approval in accordance with Commitment No. 7.

UFSAR Supplement. LRA Section A.2.1.7 provides the UFSAR supplement for the PWR Vessel Internals Program. The staff reviewed this UFSAR supplement description of the program and determines that the information in the supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's PWR Vessel Internals Program, the staff determines that this AMP is a unique plant-specific program designed as a means for fulfilling Commitment No. 7. The staff concludes that, combined with other specific Salem AMPs, the applicant has demonstrated that the effects of aging for the RPV internals 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).

3.0.3.1.8 Steam Generator Tube Integrity

Summary of Technical Information in the Application. LRA Section B.2.1.10 describes the existing Steam Generator Tube Integrity Program as consistent with GALL AMP XI.M19, "Steam Generator Tube Integrity." The applicant stated that the Steam Generator Tube Integrity Program manages the aging effects of the SGs, including the tubes, plugs, and tube support plates in reactor coolant or treated water environments.

The applicant stated that the program provides for the operation, maintenance, testing, inspection, and repair of the SGs to ensure that technical specification (TS), surveillance requirements, ASME Code requirements, and Maintenance Rule performance criteria are met. The applicant further stated that the aging effects include cracking, loss of material, reduction of heat transfer, and wall thinning. The tubing material in the SGs in Salem Units 1 and 2 is thermally-treated Alloy 600 and thermally-treated Alloy 690, respectively. The applicant stated that the dominant degradation mode for the SG tubes at Salem is wear. The program implements NEI 97-06, "Steam Generator Program Guidelines," which establishes a framework for prevention, inspection, evaluation, repair, and leakage monitoring measures. The applicant stated the following:

> The program includes preventative measures to mitigate degradation related to corrosion phenomena, assessment of degradation mechanisms, inservice inspection (ISI) of SG tubes, plugs, and tube supports to detect degradation, evaluation, and plugging or repair, as needed, and leakage monitoring to maintain the structural and leakage integrity of the pressure boundary.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M19. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M19. However, the staff noted one discrepancy in the LRA AMP relative to the GALL Report AMP which the applicant will fix under its corrective action program.

The applicant's procedure CY-AP-120-340, "Primary to Secondary Leakage Monitoring Procedures," requires entry into Action Level 3, Condition 1, when primary to secondary leakage equals or exceeds 140 gallons per day (gpd) in any SG. The GALL Report references NEI 97-06, which in turn references EPRI Report 10088219, "PWR Primary to Secondary Leakage Guidelines," Revision 3. Revision 3 of these guidelines requires entry into Action Level 3, Condition 1 when primary to secondary leakage is increasing by greater than or equal to 30 gpd/hour and is equal to or exceeding 75 gpd. During the audit, the applicant stated that the plant procedure was incorrect. The applicant has entered this into its corrective action program as Notification 20451464. The staff finds this acceptable; therefore, this issue is resolved and requires no further action.

In comparing program elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M19, the staff noted that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M19.

<u>Operating Experience</u>. LRA Section B.2.1.10 summarizes operating experience related to the Steam Generator Tube Integrity Program. The applicant replaced the original SGs in Units 1 and 2 in 1996 and 2008, respectively. The original SGs in Unit 1 were replaced with Westinghouse Model F SGs with thermally-treated Alloy 600 tubes. The original SGs in Unit 2 were replaced with AREVA 61/19T SGs with thermally-treated Alloy 690 tubes. The applicant included the following as part of the operating experience:

> A separate report following the 2004 [Unit 1] outage indicated that the estimated SG deposit ingress (sludge) has been decreasing per cycle since the replacement of the SGs in 1996. For example, the estimated sludge accumulation for all four SGs in the fourth cycle following replacement was 1086 lbs as compared to 2677 lbs estimated in the first cycle following replacement.
>
> The materials of construction for the [Unit 2] replacement SGs have better resistance to aging effects than those in the original SGs. Examples include the use of Inconel 690 thermally-treated tubes in the replacement SGs as compared to the Inconel 600 mill-annealed tubes of the original SGs. Also, the tube support plates and anti-vibration bars in the replacement SGs are made of stainless steel as compared to the carbon steel components in the original SGs.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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.

The staff confirmed that the applicant addressed operating experience identified after issuance of the GALL Report. Based on its review, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and implementation of this program has resulted in the applicant taking appropriate corrective actions. Therefore, the operating experience program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.10 provides the UFSAR supplement for the Steam Generator Tube Integrity Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Steam Generator Tube Integrity Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Open-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B.2.1.11 describes the existing Open-Cycle Cooling Water System Program as consistent with GALL AMP XI.M20, "Open-Cycle Cooling Water System." The applicant stated that its program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the open-cycle cooling water system. The applicant stated that the program provides assurance that aging effects from cracking, loss of material, increase in porosity and permeability, loss of strength, hardening, and reduction of heat transfer are maintained at acceptable levels. The applicant also stated that activities and guidelines from GL 89-13 provide for management of aging effects in raw water cooling systems. The applicant further stated that sodium hypochlorite injection, system and component testing, visual inspections, and other nondestructive examinations (NDEs) are performed to ensure that aging effects are managed. The applicant also listed major components for these systems as pumps, piping, piping elements, piping components, heat exchangers, and tanks.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M20. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M20. Based on its audit, the staff finds that elements one through six of the applicant's Open-Cycle Cooling Water System Program are consistent with the corresponding program elements of GALL AMP XI.M20 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.11 summarizes operating experience related to the Open-Cycle Cooling Water System Program. The applicant stated that because of recurrent problems in the early operation of the service water system, it began the replacement of most of the safety-related carbon steel piping with 6 percent molybdenum stainless steel, and many of the safety-related heat exchanger tube bundles were replaced with corrosion resistant titanium or 6 percent molybdenum stainless steel. The applicant stated that it upgraded materials for other component types including valves and orificies in the service water system. The applicant stated that these changes in component materials demonstrate that the Open-Cycle Cooling Water System Program is effective in detecting and correcting issues to ensure the long-term reliability of the system for the period of extended operation.

In addition, the applicant stated that Salem Unit operators discovered an underground service water leak. The applicant's investigation of the problem determined that a joint had started to leak due to a crack in the steel ring of the bell and spigot joint. The applicant determined that the cause of the joint failure was the loss of caulking, which had previously protected the carbon steel portions of the joint. As noted in the operating experience discussion of the LRA (Appendix B.2.22) for the Buried Piping Inspection Program for this issue, an extent of condition study identified internal corrosion on other bell and spigot joints, which prompted the installation of an internal elastomer seal on each joint of the nuclear service water inlet headers. The applicant stated that maintenance tasks were established to inspect the joints every other outage, in conjunction with the piping inspections. The applicant further stated that this operational experience provided evidence that the Open-Cycle Cooling Water System Program identifies and corrects deficiencies in the open-cycle cooling water system, ensuring the long-term reliability of the system for the period of extended operation.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.11 provides the UFSAR supplement for the Open-Cycle Cooling Water System Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 11) to ongoing implementation of the existing Open-Cycle Cooling Water System Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Open-Cycle Cooling Water System Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 Compressed Air Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.14 describes the existing Compressed Air Monitoring Program as consistent with GALL AMP XI.M24, "Compressed Air Monitoring." The applicant stated that the program consists of testing, monitoring, and inspection of the piping, piping components, piping elements, compressor housings, and tanks for loss of material due to general, pitting, and crevice corrosion in the compressed air systems. The applicant also stated this program includes periodic leak testing of valves, piping, and other system components, and preventive monitoring that checks air quality at multiple locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within accepted limits. The applicant further stated that the program provides for timely corrective actions to ensure that the system is operated within accepted limits.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M24. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M24. Based on its audit, the staff finds that elements one through six of the applicant's Compressed Air Monitoring Program are consistent with the corresponding program elements of GALL AMP XI.M24 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.14 summarizes operating experience related to the Compressed Air Monitoring Program. The applicant stated that the program is effective in assuring that intended functions will be maintained consistent with the CLB for the period of extended operation. The applicant also stated that on a system walkdown of the compressed air system, signs of surface rust were identified on control manifolds for Unit 1. The applicant further stated that it determined that the condition was not a threat to the integrity of the system and that no further actions were required. The applicant identified that this experience demonstrated that items were identified during system walkdowns and that these items were placed into the work planning system for corrective action and addressed prior to loss of intended function.

Further, the applicant stated that it identified a leak from a corroded cooler plug in an intercooler. Although the applicant determined the leak was small enough to not affect operability of the intercooler, it noted that a larger leak could potentially affect the compressors. The applicant also stated that it identified the plug failure was likely caused by formation of a galvanic cell between the carbon steel plug and the AL6XN steel in the service water system. The applicant further stated that a replacement plug was installed and that the plug was constructed of material compatible with the station air compressors. The applicant identified that this was an example of how system walkdowns and the corrective action process identifies and corrects issues prior to system 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.14 provides the UFSAR supplement for the Compressed Air Monitoring Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 14) to ongoing implementation of the existing Compressed Air Monitoring Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Compressed Air Monitoring Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.11 One-Time Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.20 describes the applicant's new One-Time Inspection Program as consistent with GALL AMP XI.M32, "One Time Inspection." The applicant stated that the One-Time Inspection Program will provide reasonable assurance that loss of material and cracking in a selected sample of piping, piping elements, components, SGs, tanks, and reduction of heat transfer in the heat exchanger population does not occur or that the aging effect is occurring slowly enough to not affect a component's intended function during the period of extended operation and, therefore, will not require additional aging management. The applicant also stated that the One-Time Inspection Program will be used to confirm the effectiveness of the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis programs at mitigating the effects of aging. The applicant further stated that it will use visual and volumetric inspection techniques performed per ASME Code standards and its acceptance criteria will follow station procedures based on applicable industry and regulatory codes and standards.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M32 and confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M32, with the exception of the "detection of aging effects" program element. For this element, the staff determined a need for additional clarification, which resulted in the issuance of an RAI, as discussed below.

GALL AMP XI.M32 states in the "detection of aging effects" program element that the inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The LRA states that the program elements include: (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; and (2) identification of inspection locations in the system, component, or structure based on the aging effect. However, the LRA did not state how the selected set of sample components would be determined or the size of the sample of components that would be inspected. The staff noted that due to the uncertainty in determining the most susceptible locations and the potential for aging to occur in other locations, large sample sizes may be required in order to adequately confirm that an aging effect is not occurring. By letter dated December 10, 2010, the staff issued RAI B.2.1.20-1 requesting that the applicant provide specific information regarding how the selected set of components to be sampled will be determined and the size of the sample of components that will be inspected.

In its response dated January 6, 2011, the applicant stated that it will develop a sample plan which will establish sample groups based on aging effects and environments and will be populated with the components and their materials of fabrication. The applicant also stated that a sample size of 20 percent of the population (up to a maximum of 25 inspections) will be established for each sample group. The applicant further stated that the selection of components for inspection, when possible, will be biased toward inspecting bounding or lead components most susceptible to aging in potentially more aggressive environments (e.g., low or stagnant flow areas) and selecting components with the lowest design margin. The applicant revised the program's UFSAR supplement and program description to include this information. The staff finds the applicant's response acceptable because the applicant's sampling methodology: (1) ensures a representative sample of material and environment combinations is considered, (2) ensures sample locations will focus on the most susceptible components, and (3) includes an appropriate sample size that is consistent with industry standards and practices. The staff's concerns described in RAI B.2.1.20-1 are resolved.

Based on its audit, the staff finds that elements one through six of the applicant's One-Time Inspection Program are consistent with the corresponding program elements of GALL AMP XI.M32 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.20 summarizes operating experience related to the One-Time Inspection Program. The applicant stated examples of inspections that demonstrate its success using visual and volumetric inspection techniques to evaluate loss of material and thinning in pipes connected to the high pressure feedwater heater outlet vent valve and in the service water and moisture separator drains systems. The applicant also stated that it will apply the same techniques in its One-Time Inspection Program and, therefore, the program will be as effective as its previous inspections in identifying aging effects in relevant systems and components. In addition, for systems that credit the One-Time Inspection Program for aging management, the applicant reviewed Maintenance Rule and System Health reports and identified that none of the aging effects being managed by the One-Time Inspection Program negatively impacted any of those systems' performance or caused any loss of component intended function for these systems. The applicant further stated that the overall condition of these systems with respect to the applicable aging effects, coupled with the one-time inspections, provide sufficient confidence that implementation of the One-Time Inspection Program will effectively identify and manage degradation that could lead to failure.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.

<u>UFSAR Supplement</u>. LRA Section A.2.1.20 provides the UFSAR supplement, as amended by letter dated January 6, 2011, for the One-Time Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 20) to implement the new One-Time Inspection Program prior to entering the period of extended operation for managing aging of applicable components. The staff further notes that the applicant committed (Commitment No. 20) to utilize the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage loss of material and cracking in stainless steel components in a treated borated water environment.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's One Time Inspection Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement, as amended, 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 Selective Leaching of Materials

Summary of Technical Information in the Application. LRA Section B.2.1.21 describes the new Selective Leaching of Materials Program as consistent with GALL AMP XI.M33, "Selective Leaching of Materials." The applicant stated that the Selective Leaching of Materials Program ensures the integrity of components made of cast iron, bronze, brass, and other alloys exposed to raw water, brackish water, treated water, or soil environments that may lead to selective leaching of one of the metal components. The applicant also stated that the AMP includes a one-time visual inspection and hardness measurements of selected components that may be susceptible to selective leaching to identify whether material loss from selective leaching is occurring and if selective leaching will affect the ability of components to perform their intended function during the period of extended operation. The applicant further stated that aging management activities, such as periodic inspections and trending, will be implemented to manage the aging effects where selective leaching is identified. Based upon an observation during the regional license renewal inspection, IP-71002, the applicant amended its LRA by letter dated September 1, 2010, to include aging management activities, such as periodic inspections and trending, to manage the aging effects for material and environment combinations where selective leaching is identified.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M33 and confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M33, with the exception of the "scope of the program" program element. For this element, the staff determined a need for additional clarification, which resulted in the issuance of an RAI, as discussed below.

GALL AMP XI.M33 states in the "scope of the program" program element that the program includes a one-time visual inspection and hardness measurement of a selected set of sample components to determine whether loss of material due to selective leaching is not occurring for the period of extended operation. However, the LRA did not state how the selected set of sample components would be determined or the size of the sample of components that would be inspected. The staff noted that due to the uncertainty in determining the most susceptible locations and the potential for aging to occur in other locations, large sample sizes may be required in order to adequately confirm that selective leaching is not occurring. By letter dated December 10, 2010, the staff issued RAI B.2.1.21-1 requesting that the applicant provide specific information regarding how the selected set of components to be sampled will be determined and the size of the sample of components that will be inspected.

In its response dated January 6, 2011, the applicant stated that the sample size and inspection locations for the one-time inspections will be developed to ensure that a representative sample of material and environment combinations is selected with a focus on the leading indicator components. The applicant also stated that the representative sample size and one-time inspection locations will be based on the population of components with the two susceptible materials of fabrication. The applicant further stated that a sample size of 20 percent of the population of copper alloy components susceptible to selective leaching and 20 percent of the population of gray cast iron components susceptible to selective leaching will be established with up to a maximum of 25 inspections per population. The applicant revised the program's UFSAR supplement and program description to include this information. The staff finds the applicant's response acceptable because the applicant's sampling methodology: (1) ensures a representative sample of material and environment combinations is considered, (2) ensures sample locations will focus on known susceptible components, and (3) includes an appropriate sample size that is consistent with industry standards and practices. The staff's concerns described in RAI B.2.1.21-1 are resolved.

Based on its audit, the staff finds that elements one through six of the applicant's Selective Leaching of Materials Program are consistent with the corresponding program elements of GALL AMP XI.M33 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.21 summarizes operating experience related to the Selective Leaching of Materials Program. In one operating experience example, the applicant stated that de-alloying of a service water aluminum bronze strainer drum in brackish water was identified by visual inspection during maintenance being performed on the strainer while offsite. The applicant also stated that additional examinations and evaluations were performed and that it created a routine maintenance activity for refurbishment of these components on a 6-year frequency to ensure that the strainer drum continues to properly fulfill its intended function. The applicant further stated that this operating experience demonstrates that it has identified selective leaching and taken corrective actions to monitor and refurbish material that is susceptible to selective leaching.

In another operating experience example, the applicant stated that it identified the graphitization of gray cast iron submerged pump components from long-term immersion in saltwater and brackish water environments through visual inspection of cast iron pump casing components in the circulating water system. The applicant also stated that as a consequence of the identification of this issue, inspections or refurbishment of these components are now performed on a 3-year frequency. The applicant further stated that this operating experience demonstrates that it has identified selective leaching and taken corrective actions to monitor and maintain material that is susceptible to selective leaching.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.21 provides the UFSAR supplement, as amended by letter dated January 6, 2011, for the Selective Leaching of Materials Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, and 3.3-2. The staff also notes that the applicant committed (Commitment No. 21) to implement the new Selective Leaching of Materials Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Selective Leaching of Materials Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement, as amended, 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 External Surfaces Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.24 describes the new External Surfaces Monitoring Program as consistent with the program elements in GALL AMP XI.M36, "External Surfaces Monitoring." The applicant stated that its program is a condition monitoring program that relies on observations made during visual inspections. The applicant also stated that it relies on this program to preliminarily detect occurrences of corrosion by inspecting for degradation of coatings and the appearance of visually apparent corrosion products on steel components. The applicant further stated that the visual inspections conducted within this program serve to detect degradation of steel components prior to any loss of intended function.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M36. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M36. Based on its audit, the staff finds that elements one through six of the applicant's External Surfaces Monitoring Program are consistent with the corresponding program elements of GALL AMP XI.M36 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.24 summarizes operating experience related to the External Surfaces Monitoring Program. In one example of operating experience, the applicant stated that during the visual inspections conducted in this program, rust was detected on carbon steel pipes due to leakage in the containment fan cooler units at Salem Unit 2 and that the corrective actions implemented included repair of the leaks. The applicant also stated that this instance of operating experience illustrates the effectiveness of the program.

In another example of operating experience, the applicant stated that it detected surface corrosion on piping associated with an evaporative cooler in Salem Unit 1 and that an engineering assessment determined the corrosion was caused by lack of insulation. The applicant also stated that it inspected other similar coolers in service at Salem Unit 1 and found that the affected unit was not insulated equivalently to the others. The applicant further stated that the corrective actions included addition of insulation to the affected unit and follow-up inspections to confirm that the corrective action was effective in mitigating further corrosion.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of corrosion 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.2.1.24 provides the UFSAR supplement for the External Surfaces Monitoring Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 24) to implement the new External Surfaces Monitoring Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's External Surfaces Monitoring Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.14 Flux Thimble Tube Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.1 describes the new Flux Thimble Tube Inspection Program as consistent with GALL AMP XI.M37, "Flux Thimble Tube Inspection." The applicant stated that the Flux Thimble Tube Inspection Program manages loss of material due to wear of the flux thimble tube materials and that it implements the recommendations of NRC Bulletin 88-09. The applicant further stated that the program uses an inspection methodology such as eddy current testing (ECT) to inspect the flux thimble tubes on a periodic frequency to monitor wall thinning and predict when tubes will require repair or replacement. The applicant also stated that the Flux Thimble Tube Inspection Program establishes appropriate acceptance criteria (percentage through-wall wear), based on industry guidance, and includes sufficient allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies applicable for the inspection methodology. The applicant stated that where the flux thimble tube through-wall wear does not meet the established criteria, the tube must be isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained.

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

The staff compared elements one through six of the applicant's program with the corresponding elements of GALL AMP XI.M37. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M37, with the exception of the "monitoring and trending" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

The staff noted that the applicant identified its Flux Thimble Tube Inspection Program as a "new" program because in 1993 the applicant discontinued the ECT of flux thimble tubes recommended in NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." The staff reviewed the history of the applicant's earlier Flux Thimble Tube Inspection Program, noting that in the early 1980s, the applicant experienced a number of failures in its original flux thimble tubes and in 1988, the applicant implemented flux thimble tube ECT in accordance with its original response to NRC Bulletin 88-09. The staff noted that in 1990, the applicant replaced all of its flux thimble tubes in Units 1 and 2 with a new, wear-resistant thimble tube design consisting of an outer pressure boundary tube and a concentric dry guide path inner tube. The staff noted that in a letter dated December 20, 1993, the applicant submitted a supplemental response to NRC Bulletin 88-09 providing an evaluation of the new thimble tube design and justification for discontinuing its Flux Thimble Tube Inspection Program. In a letter dated April 15, 1994 (Agencywide Document Access and Management System (ADAMS) Accession No. ML9404220015), the staff issued a safety evaluation of the applicant's supplemental response to NRC Bulletin 88-09 accepting the applicant's proposal to discontinue the Flux Thimble Tube Inspection Program.

During the audit, the staff asked the applicant to: (1) clarify whether any ECT of its flux thimble tubes has been performed since issuance of the staff's safety evaluation dated April 15, 1994, (3) clarify whether any flux thimble tubes have been replaced since that date, and (3) explain how failure of a flux thimble tube's RCPB would be detected, if it should occur. In response to these questions, the applicant stated that: (1) there have been no ECT of flux thimble tubes performed since issuance of the staff's safety evaluation; (2) some flux thimble tubes have been replaced, but not because of RCPB failure or failure caused by wear; and (3) a leak detection system monitors any leakage from flux thimble tubes, and no such leakage has been observed since replacement of the original flux thimble tubes with the improved design.

The staff noted that in GALL AMP XI.M37, the "monitoring and trending" program element states that flux thimble tube wall thickness measurements will be trended and wear rates calculated, with examination frequency based on plant-specific wear projections, and that re-baselining of the examination frequency should be justified using plant-specific wear rate data unless prior plant-specific NRC acceptance for the re-baselining was received. As documented in the Audit Report, the staff noted that there have been no flux thimble tube examinations during the past 16 years; however, the applicant stated that it will conduct flux thimble tube inspections during the refueling outages prior to entering and during the period of extended operation to baseline the wall thickness and provide data for wear predictions. The staff noted that the applicant's statement that it will conduct a flux thimble tube inspection during the refueling outage prior to entering the period of extended operation is consistent with LRA Section A.5, "License Renewal Commitment List," Commitment No. 5. However, because the applicant has no current plant-specific wear rate data, it was not clear to the staff how the applicant will re-baseline its current condition of flux thimble tube wear, consistent with recommendations in GALL AMP XI.M37. By letter dated June 10, 2010, the staff issued RAI B.2.1.25-01 requesting that the applicant: (1) explain how the baseline condition of the flux thimble tube walls will be established when ECT is reinstituted prior to entering the period of extended operation and (2) explain how plant-specific flux thimble tube wear rates will be determined and projected to ensure that acceptance criteria for flux thimble tube wall thickness will continue to be met during the operating interval between subsequent flux thimble tube inspections.

In its response dated July 8, 2010, the applicant stated that it will prepare and approve a Flux Thimble Tube Inspection Program, consistent with LRA Appendix B, Section B.2.1.25, prior to entering the period of extended operation and that it will perform 100 percent inspection of the flux thimble tubes (58 thimbles per unit) during refueling outages in the period of extended operation using ECT or other comparable NDE in accordance with NRC Bulletin 88-09. The applicant stated that all new flux thimble tubes (using the tube-in-tube design) were installed in December 1987 and October 1988 on Salem Units 1 and 2, respectively, and that during August 1993, it conducted a wear evaluation of those flux thimble tubes using a combination of ECT and UT of 11 new design flux thimbles that had been removed from Salem Unit 1. The applicant further stated that its evaluation concluded that less than 3 percent wear was observed on any of the removed flux thimble tubes, which had been in service for approximately 4 years.

The applicant stated that it will reestablish the baseline condition of each flux thimble tube by: (1) taking as-found measurements over the entire length of each tube, (2) comparing the as-found measurements against the data taken on flux thimble tubes evaluated in 1993, and (3) comparing data taken in the wear region of the flux thimble tubes against data taken in the non-wear regions of the flux thimble tubes. The applicant stated that it will: (1) measure and compare the wall thicknesses of flux thimble tube portions outside the reactor vessel (non-wear portion) with the wall thickness of flux thimble tube portions within the lower core plate region (wear portion) and (2) include results of these measurements and comparisons to determine the baseline conditions of the flux thimble tubes.

The applicant stated that it will determine plant-specific wear rates by comparing the as-found wall thickness measurements taken during examination of flux thimble tubes to the wall thicknesses documented in drawings and specifications during original installation of the new flux thimbles. The applicant also stated that since the initial modification installed in 1987 and 1988, it has replaced more than 25 percent of the new flux thimble tubes in each Unit due to reasons unrelated to leakage or wear (problems with the thermocouple readings or loss of flux detector insertion capability). The applicant further stated that it will: (1) use measurements taken on the replaced flux thimble tubes, which have varying inservice times up to approximately 20 years, to determine wear rates as a function of inservice time; (2) include comparison of wall thicknesses between non-wear and wear portions in determining average wear rates for the flux thimble tubes; (3) project future wear for each flux thimble tube by applying the tube's estimated wear rate to its baseline condition over its inservice time; and (4) compare the projected wear and resulting predicted wall thickness loss against the acceptance criterion (nominally 70 percent of wall thickness material) to ensure that the integrity of the flux thimble tubes will be maintained during the operating interval between subsequent flux thimble tube inspections.

The staff noted that the applicant's process for reestablishing baseline conditions of the flux thimble tubes includes 100 percent of the flux thimble tubes and that it compares ECT (or comparable) wall thickness measurements of thimble tubes against both design specifications and measurements of tube thicknesses in non-wear portions of the flux thimbles. The staff also noted that the applicant's acceptance criterion for projected wall thickness loss (70 percent of wall thickness) ensures that minimum wall thickness is maintained at least a factor of 10 greater than the maximum wear observed over a 4-year period for thimble tubes of a similar design that the applicant examined in 1993. The staff finds the applicant's acceptance criterion adequate to ensure that integrity of the RCPB is maintained, including allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies.

Based on its review, the staff finds the applicant has responded acceptably to RAI B.2.1.25-01 because the methodology for reestablishing the baseline for the flux thimble tubes: (1) includes every flux thimble tube, (2) includes plant-specific wear data over different time periods, and (3) compares as measured wall thickness in tubes with both design data and as measured wall thickness in areas of the tubes that do not experience wear. The staff also finds the applicant's process for determining and applying flux thimble tube wear rates is: (1) based on plant-specific measurements, (2) based on acceptable criteria, and (3) requires corrective actions be taken before unacceptable reductions in wall thickness occurs. The staff's concern described in RAI B.2.1.25-01 is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.25-01, the staff finds that elements one through six of the applicant's Flux Thimble Tube Inspection Program are consistent with the corresponding program elements of GALL AMP XI.M37 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.25 summarizes operating experience related to the Flux Thimble Tube Inspection Program. The applicant stated that the Flux Thimble Tube Inspection Program was in effect from 1985 to 1993, and it was discontinued in 1993 after the replacement of the flux thimble tubes with an alternative design and follow-up inspections that did not find significant wear. The applicant provided three examples of its operating experience from 1981 through 1993:

> The applicant stated that Salem Unit 1 replaced in-kind all of its flux thimble tubes in 1981 after experiencing three at-power thimble leaks, and in 1985 it performed ECT on all of the new flux thimble tubes, finding wall losses of over 50 percent for ten (10) thimble tubes. The applicant further stated that all ten thimble tubes were isolated. The applicant also stated that the possible cause was believed to be flow induced vibration at the lower core support. The applicant stated that new flux thimble tubes of an improved design were installed in 1990 to replace all of the existing tubes and inserts for the lower internals were installed to prevent flow-induced vibration wear.
>
> The applicant stated that Salem Unit 2 used ECT to inspect its flux thimble tubes in 1984 and that possible external damage or wall [loss] was observed on sixteen (16) tubes where they passed through the lower core support. The applicant further stated that in 1986, during the subsequent refueling outage, ECT was used and the results indicated wall losses of over 40 percent for three (3) flux thimble tubes, with these tubes subsequently being isolated. The applicant also stated that during the 1990 refueling outage, Unit 2 replaced all of its flux thimble tubes with an improved design.

> The applicant stated that during the Unit 1 1993 outage, ECT was performed on eleven (11) of the improved design flux thimble tubes that had been removed and stored in the spent fuel pit. The applicant stated that the results of the ECT inspection indicated that there was no significant wear on any of the eleven flux thimble tubes, and that the indications that were found were attributed to incomplete tube cut scars and partial tube cuts. The applicant further stated that the examination indicated that no cladding bulging or ovality was detected. The applicant also stated that as a result of the examinations, Salem notified the NRC that it would discontinue future periodic inspections of flux thimble tubes.

The applicant stated that these examples demonstrate that aging effects and mechanisms were adequately managed during past implementation and that re-implementation of the Flux Thimble Tube Inspection Program will effectively identify degradation prior to failure. The applicant further stated that the program will provide appropriate guidance for re-evaluation, repair, or replacement if degradation is found.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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 of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.25 provides the UFSAR supplement for the Flux Thimble Tube Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 25) to implementing the new Flux Thimble Tube Inspection Program prior to the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's Flux Thimble Tube Inspection Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.15 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B.2.1.26 describes the new Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program as consistent with GALL AMP XI.M38, "Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components." The applicant stated that this program manages the internal surfaces of steel piping; piping components and elements; ducting components; tanks; and heat exchanger components exposed to air/gas wetted, diesel exhaust, or raw water for loss of material. The applicant stated that this program includes provisions for visual inspections of the internal surfaces of components not managed under other AMPs. The applicant also stated that inspections will be performed when internal surfaces are accessible during maintenance, surveillances, and scheduled outages. For painted or coated surfaces, the applicant stated that it will monitor the condition of the painted or coated finish as an indicator for corrosion of the underlying steel. Surface fouling is monitored to assess the effectiveness of heat exchanger components. The applicant further stated that operating history will be taken into consideration to determine the frequency of inspections and that a representative sample of locations will also be taken into consideration.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M38. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M38 with the exception of the "detection of aging effects" program element. For this element, the staff determined the need for additional clarification.

When the staff compared the LRA program description, which suggests the use of a "representative sample," to the GALL AMP XI.M38 "detection of aging effects" program element recommendations on sampling, it was unclear to the staff how the applicant defined its "representative sample" (i.e., the population criteria, size, and sampling methodology used). On August 18, 2010, the staff held a telephone conference with the applicant (ADAMS Accession No. ML102460095) to clarify the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program's sampling methodology, including how the population for each of the material-environment-aging effect combinations is being selected and what type of engineering, design, or operating experience considerations would be used to select the sample of components for both the scheduled and supplemental inspections. During this discussion, the applicant stated that the program will ensure that for each material, environment, and aging effect combination, representative inspections will be conducted as directed by formal preventive maintenance or recurring tasks within the work management system. The applicant also stated that the intent is to use existing preventive maintenance or recurring task activities augmented with new recurring task activities to address the inspection of material, environment, and aging effects not adequately addressed by the current activities. The applicant further stated that if adverse conditions are identified, they will be entered into a corrective action program, discussed in the LRA, and appropriate actions will be directed including identifying and evaluating the cause and extent of the condition(s). The staff finds the applicant's response acceptable and the "detection of aging effects" program element consistent with the corresponding element of GALL AMP XI.M38 because its representative sample will include inspections for each material, environment, and aging effect combinations and when degradation is found, it will be entered in the corrective action program.

Based on its audit, the staff finds that elements one through six of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program are consistent with the corresponding program elements of GALL AMP XI.M38 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.26 summarizes operating experience related to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant stated that industry operating experience indicates that it is possible to sustain age-related degradation on internal surfaces of susceptible components, but that visual inspections of internal surfaces at the plant showed only minimal internal degradations. The applicant also stated the following two examples of plant operating experience which demonstrate the effectiveness of the relevant plant procedures on maintenance, walkdowns, and systems checks: (1) an extensive maintenance history search and interviews with system managers for the ventilation systems that are within the scope of license renewal was performed and revealed no evidence of age-related degradation and (2) review of the emergency diesel generator (EDG) turbo boost air receiver tanks and starting air receiver tanks inspections, where the applicant visually inspected the internal surfaces and probed suspect locations using UT to measure their wall thickness, was performed. Inspections performed over a 5-year period (2003–2008) indicated that the tanks were generally clear of rust, except for a few minor rust or scaling spots which were cleaned, and follow-up UT measurements confirmed that significant loss of material was not occurring. The applicant further stated that these examples provide objective evidence that existing maintenance activities are effective at identifying internal degradations, and any degradation is monitored and evaluated to preserve 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.26 provides the UFSAR supplement for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 26) to implement the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.16 ASME Section XI, Subsection IWL

Summary of Technical Information in the Application. LRA Section B.2.1.29 describes the existing ASME Section XI, Subsection IWL Program as consistent with GALL AMP XI.S2, "ASME Section XI, Subsection IWL." The applicant stated that the ASME Section XI, Subsection IWL Program implements examination requirements of ASME Code Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC), 1998 Edition with the 1998 Addenda. The applicant further stated that the program requires periodic inspection of containment structure concrete surfaces as specified by ASME Code Section XI, Subsection IWL and approved alternatives in accordance with 10 CFR 50.55a. In addition, in response to RAI B.2.1.29-1, dated May 4, 2010, the applicant stated that prior to the period of extended operation, the program elements will be enhanced to include concrete surface examination and acceptance criteria in accordance with the guidance contained in American Concrete Institute (ACI) 349.3R.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the enhancement the applicant submitted in response to RAI B.2.1.29-1 to determine whether the AMP, with the enhancement, is adequate to manage the aging effects for which the LRA credits it. The staff confirmed that the ASME Section XI, Subsection IWL Program contains all the elements of the referenced GALL Report program and that the plant conditions are bounded by the conditions for which the GALL Report was evaluated.

Enhancement. In response to RAI B.2.1.29-1, the applicant added an enhancement to the "acceptance criteria" program element in LRA Section B.2.1.29. The enhancement involves implementation of examination and acceptance criteria in accordance with the guidance contained in ACI 349.3R prior to the period of extended operation. The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S2. The staff determined that inclusion of ACI 349.3R concrete acceptance criteria in the ASME Section XI, Subsection IWL Program is acceptable because GALL AMP XI.S2 states that quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer.

Based on its review, the staff finds that elements one through six of the applicant's ASME Section XI, Subsection IWL Program, with acceptable enhancement, are consistent with the corresponding program elements of GALL AMP XI.S2 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.29 summarizes operating experience related to the ASME Section XI, Subsection IWL Program. The applicant completed a second examination of accessible concrete surfaces for the Salem Units 1 and 2 containment structures in accordance with the ASME Section XI, Subsection IWL Program in October 2005 and May 2005, respectively. The applicant stated that the examinations consisted of general visual examinations to assess the structural condition of the containment as required by IWL-2310. The applicant stated that the degradation consisted of minor local surface scaling and spalling (less than 3 inches deep for Unit 1 and 2 inches deep for Unit 2 as documented in the corrective action report) of concrete on exterior surfaces of the containment, rust stains attributed to embedded concrete inserts, localized efflorescent (leaching), and normal shrinkage cracks. The applicant also stated that examiners qualified as specified in IWL-2310 conducted the examinations and documented the results in a corrective action report. The applicant further stated that areas of observed degradation were evaluated and accepted by the responsible engineer. The applicant concluded that this example demonstrates that loss of material (scaling and spalling) and potential reinforcing bar corrosion (rust stains) are detected and evaluated before they have impact on containment reinforced concrete structural integrity.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified operating experience which could indicate that the applicant's program may not be effective in adequately managing aging effects during the period of extended operation. The staff determined the need for additional clarification, which resulted in the issuance of two RAIs.

In LRA Section B.2.1.29, the applicant stated that spalling of concrete containment surfaces did not exceed a depth of 2 inches for Unit 2 and 3 inches for Unit 1 during recent inspections conducted in accordance with ASME Code Section XI, Subsection IWL. During the audit, the staff noted that these areas of observed degradation were evaluated and accepted by the responsible professional engineer based on acceptance criteria in the Salem inspection procedure S-C-CAN-SEE-1353, Revision 0. In addition, a notification issued by the applicant describes the condition of the concrete on the north side of the Unit 2 containment involving surface spalling ranging up to 6 feet long and 16 inches wide, and spalling at joints ranging up to 3 feet long and 4 inches wide. The notification also describes a condition on the north side of the Unit 2 containment between the equipment hatch and the fuel handling penetration area involving the protrusion of a pipe from the penetration wall. The notification further describes a piece of wood (1 inch by 8 inches by 4 inches) protruding from the penetration wall in the main steam area.

The staff was concerned about the extent of spalling on the Units 1 and 2 containment exterior surface and the other issues reported in the notification issued by the applicant. Therefore, by letter dated April 15, 2010, the staff issued RAI B.2.1.29-1 requesting that the applicant: (1) provide the basis for the acceptance criteria in Section 5.4 of S-C-CAN-SEE-1353, Revision 0 including the reasons for it being significantly less stringent than the ACI 349.3R requirements; (2) provide information about the broken pipe and flange protruding from the containment surface and its impact on the containment leak tightness; (3) confirm that the piece of wood (1 inch by 8 inches by 4 inches) is not embedded in the concrete containment wall; and (4) provide details of corrective actions that the applicant plans to implement for using the acceptance criteria described in Section 5.4 of S-C-CAN-SEE-1353, Revision 0 which do not conform with the current industry practice nor with ACI 349.3R.

In its response dated May 13, 2010, the applicant responded to RAI B.2.1.29-1, issues (1) and (4) by stating that S-C-CAN-SEE-1353 is no longer an active document in the Salem document control system and that the ASME Section XI, Subsection IWL Program examination procedures now use the guidance provided in ACI 349.3R. The applicant initiated corrective actions as a result of differences between the acceptance criteria provided in Section 5.4 of S-C-CAN-SEE-1353, Revision 0, which do not conform with the current industry practice described in ACI 349.3R. The applicant stated that a visual inspection of the concrete containment, using the ACI 349.3R tiered acceptance criteria, was done for both Salem Units 1 and 2 in April 2010. The results of the inspection were reviewed by the site responsible professional engineer and determined to satisfactorily meet all ACI 349.3R acceptance criteria.

The applicant responded to RAI B.2.1.29-1, issue (2) by stating that the broken pipe and flange reported in the notification does not protrude from the Unit 2 containment wall. The pipe is located in a wall extending outwards from the fuel handling building and has no impact on the containment leak tightness. In response to RAI B.2.1.29-1 issue (3), the applicant stated that the notification "describes a piece of wood (1 in. by 8 in. by 4 in.) that is not embedded in any concrete and is not touching the Containment. The piece of wood is wedged between miscellaneous steel and the mechanical penetration area wall of the Auxiliary Building, near the Containment wall. This piece of wood has no impact on containment integrity."

The staff finds the applicant's response to RAI B.2.1.29-1 acceptable because age-related degradation of concrete within the scope of ASME Code Section XI, Subsection IWL is being managed in accordance with applicable requirements in ASME Code Section XI, Subsection IWL, including an enhancement to its existing program that involves use of examination and acceptance criteria in ACI 349.3R to augment the qualitative assessment by the responsible engineer. Also, the applicant stated that the less stringent concrete surface inspection criteria delineated in procedure S-C-CAN-SEE-1353 is no longer in use. In addition, the applicant has performed concrete containment inspections for both Salem Units 1 and 2 in April 2010 using the ACI 349.3R tiered acceptance criteria. Inspection results were reviewed by the site responsible professional engineer and determined to satisfactorily meet all ACI 349.3R acceptance criteria. The broken pipe and flange and piece of wood reported in the notification will not affect its leak tightness and structural integrity since these items are not connected to the Unit 2's containment. The staff concludes that this aging effect is being managed in a manner that is consistent with GALL AMP XI.S2. The staff's concern described in RAI B.2.1.29-1 is resolved.

Program element 10 for the ASME Section XI, Subsection IWL Program describes results of Units 1 and 2 containment concrete surface inspections. Physical damage to concrete surfaces and normal shrinkage cracking were observed during these inspections. The staff was concerned about the long-term exposure of concrete cracks to salt spray originating from the Delaware Bay since it could result in corrosion of the embedded steel reinforcing bars located nearest to the outer surface of the containment concrete during the period of extended operation. Therefore, by letter dated April 15, 2010, the staff issued RAI B.2.1.29-2 requesting that the applicant describe: (1) the extent and maximum width of the cracks observed in Salem Unit 1 and 2 containments, (2) actions that are planned to mitigate the consequences of chloride ion penetration to the level of the embedded steel reinforcing bars over the period of extended operation, and (3) an assessment of this time-dependent phenomenon and the basis for deciding whether or not actions are anticipated to mitigate the consequences of chloride ion penetration to the level of the embedded steel reinforcing bars.

In its response to RAI B.2.1.29-2 issue (1), dated May 13, 2010, the applicant stated that concrete inspections for both Salem Units 1 and 2 containment structures were completed in April 2010 using the ACI 349.3R tiered acceptance criteria. During these inspections, pattern cracking on about a 15-inch by 15-inch grid with crack widths of about 0.015 inch was observed over most of the Unit 1 and 2 containment cylindrical walls and dome. However, some areas at the top of the dome had cracks up to 0.040 inch. In addition, cracks with widths of 0.0625 inch were observed around the Unit 2 containment air lock. The maximum crack width in the Unit 1 containment was 0.032 inch, which was observed inside the penetration area.

The applicant's responsible professional engineer reviewed the concrete surface examination results described above and found them acceptable, meeting ACI 349.3R acceptance criteria. This conclusion was based on a comparison with the cracks found during the original startup structural integrity tests. The cracks are characterized as passive and inactive. The applicant further stated that the extent of the cracking and maximum crack widths is expected and consistent with the crack patterns exhibited following the original startup structural integrity tests. Widening of cracks at the surface was identified and evaluated as part of the original structural integrity tests and accepted as a shallow, surface condition that was acceptable. In addition, during a conference call on June 30, 2010, the applicant stated that the cracks are not uniform and also reopened during subsequent integrated leak rate tests (ILRTs). Surface widening due to weathering was evident at the surface of the wider cracks. It could be seen that the cracks are narrower, less than 0.25 inch, into the concrete and considered passive. Therefore, per ACI 349.3R, no further evaluation is required. Salem will monitor and track these cracks.

The staff reviewed the applicant's response concerning the extent and width of the cracks in the Unit 1 and 2 containment concrete and found it acceptable because the width of the cracks is generally about 0.015 inch and is located as expected, consistent with the outer layer of the reinforcing bar spacing of 15 inches. In addition, these cracks are passive and inactive. Section 5.1 of the ACI 349.3R considers passive cracks acceptable without any further evaluation. Cracks with widths of 0.040 inch in the upper part of the Unit 1 and 2 containment domes are also acceptable because the cracks are inactive and were observed during the original startup structural integrity tests. Section 5.2 of the ACI 349.3R considers inactive and passive cracks with maximum widths of 0.040 inch acceptable if inactive degradation can be determined by the quantitative comparison of current observed conditions with that of prior inspections. The 0.0625-inch wide crack observed around the Unit 2 containment air lock is also acceptable because the crack is passive and does not extend more than ¼ inch into the concrete. This passive and shallow crack is not likely to cause loss of monolithic behavior or corrosion of steel reinforcement. In addition, the applicant will monitor and track the cracks in the future.

In response to RAI B.2.1.29-2, issue (2), the applicant stated that the Unit 1 and 2 concrete containment surfaces were not spalled up to 3 inches, but rather had minor scaling and spalling. Therefore, there is currently no need for specific mitigative actions to prevent the potential of chloride ion penetration to the level of embedded reinforcing bars. However, if acceptance criteria specified in ACI 349.3R for spalling, scaling, and cracking cannot be met, corrective actions will be implemented. These actions may include mitigative measures, such as repairs to scaled and spalled areas of concrete and sealing of cracks to minimize penetration of chloride ions.

The staff reviewed the applicant's response to RAI B.2.1.29-2, issue (2) and found it acceptable because the recent Unit 1 and 2 containment concrete surface examinations performed in

April 2010 identified minor spalling and scaling. The spalling did not exceed 2 inches or extend to the depth of cover for the outer layer of reinforcing bars, and cracks are inactive and passive. Therefore, the staff agrees with the applicant's conclusion that there is no need to implement any repairs or mitigation measures at this time.

In response to RAI B.2.1.29-2, issue (3), the applicant stated that the Salem containments are constructed of concrete that conforms to the applicable ACI 318 requirements. The minimum concrete clear cover over the reinforcing bars shown on the design drawings is 3-3/8 inches nominal which is greater than the 2-inch cover required by ACI 318 for concrete exposed to weather. Recent examinations of Unit 1 and 2 containment concrete surfaces using procedures that are based on ACI 349.3R inspection and acceptance criteria identified only minor spalling and scaling, but none that reduce the concrete cover over the reinforcing bars below the 2 inches required by ACI 318. Cracking is minor as described in the response to RAI B.2.1.29-2, issue (1). In addition, the containment concrete is observed to be free of large penetrating cracks that could permit significant chloride ion penetration to reach the level of reinforcing bars.

The applicant further stated that if chloride penetrates to the level of the reinforcing bars and initiates corrosion, the increase in volume of the steel due to the creation of rust will result in spalling, cracking, delamination of concrete, and staining of concrete surfaces. Implementation of the ASME Section XI, Subsection IWL Program described in LRA B.2.1.29 is considered to provide reasonable assurance that these aging effects will be detected and corrective actions will be taken prior to the loss of the containment intended function.

The staff reviewed the applicant's response to RAI B.2.1.29-2, issue (3) and found it acceptable because the reinforcing bars in the Unit 1 and 2 containments have a minimum clear concrete cover of 3-3/8 inches which is greater than the 2-inch cover required by ACI 318 for concrete exposed to weather. Visual inspection of exposed concrete surfaces for the Unit 1 and 2 containments conducted in April 2010 in accordance with the ASME Section XI, Subsection IWL Program did not identify any large penetrating active cracks that could permit significant chloride ion penetration and corrode reinforcing bars. Periodic visual inspection of Unit 1 and 2 containment concrete surfaces every 5 years as a part of the applicant's ASME Section XI, Subsection IWL Program will ensure that chloride ion penetration to the outer layer of the reinforcing bars is detected before it can adversely affect the structural integrity of the containment.

Based on its audit, review of the application, and review of the applicant's responses to RAIs B.2.1.29-1 and B.2.1.29-2, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.29 provides the UFSAR supplement for the ASME Section XI, Subsection IWL Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.5-2. The description includes a commitment by the applicant to perform periodic inspection of containment structure concrete surfaces using inspection methods, parameters, and acceptance criteria that are in accordance with ASME Code Section XI, Subsection IWL as approved by 10 CFR 50.55a. The applicant also committed to evaluating observed conditions that have the potential for impacting an intended function for acceptability in accordance with ASME Code Section XI, Subsection IWL requirements or corrected in accordance with the corrective action program. In addition, the applicant committed to enhance its ASME Section XI, Subsection IWL Program by including examination and acceptance criteria in accordance with guidance contained in ACI 349.3R.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI, Subsection IWL Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff also reviewed the enhancement and confirmed that its implementation through Commitment No. 29 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. 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 ASME Section XI, Subsection IWF

Summary of Technical Information in the Application. LRA Section B.2.1.30 describes the existing ASME Section XI, Subsection IWF Program as consistent with GALL AMP XI.S3, "ASME Section XI, Subsection IWF." The applicant's ASME Section XI, Subsection IWF Program consists of periodic inspections including visual examination of Class 1, 2, and 3 piping and component supports for loss of material and loss of mechanical function in indoor air, outdoor air, air with steam or water leakage, and treated borated water environments.

Bolting for supports is also included with these components and inspected for loss of material and preload by inspecting for missing, detached, or loosened bolts and nuts. According to the applicant, the program relies on the design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque. Identified degradation concerns are entered in the corrective action program for evaluation or correction to ensure the intended function of the affected component support is maintained. The applicant also stated that the program is implemented through corporate and station procedures, which provide inspection and acceptance criteria consistent with the requirements of ASME Code Section XI, Subsection IWF, 1998 Edition through the 2000 Addenda as approved in 10 CFR 50.55a. The applicant further stated that the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval in accordance with 10 CFR 50.55a(g)(4)(ii).

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S3. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL

AMP XI.S3. Based on its audit, the staff finds that elements one through six of the applicant's ASME Section XI, Subsection IWF Program are consistent with the corresponding program elements of GALL AMP XI.S3 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.30 summarizes operating experience related to the ASME Section XI, Subsection IWF Program. The first example of operating experience described by the applicant in LRA Section B.2.1.30 occurred in 2005 during inspection of Salem Unit 1. The inspection involved VT-3 of 125 ASME Class 1, 2, and 3 component supports and was performed in accordance with ASME Code Section XI, Subsection IWF. The supports consisted of a sample of support types (i.e., anchor, guide, support, etc.) selected from the auxiliary feedwater, chemical volume control, component cooling, containment spray, reactor coolant, RHR, main steam, safety injection, and service water systems. Qualified VT-3 examiners observed no unacceptable indications on 113 of the 125 supports, but 12 supports had indications that required further evaluation. The indications on 11 supports were related to spring hanger settings that were outside acceptable tolerances. The indication on the remaining support was related to concrete cracks observed on the component cooling heater exchanger (11 CCHX) concrete pedestal support. A corrective action report was issued to document and evaluate the observed indications. Evaluation of the as-found condition of the spring hangers prompted inspection scope increase in accordance with IWF-2430. The scope increase resulted in additional unacceptable spring hangers. All identified spring hangers with out-of-tolerance settings were adjusted to meet design requirements and re-examined in accordance with IWF-3122.2. The concrete cracks on the 11 CCHX support pedestal were evaluated by engineering, determined not to impact structural integrity of the pedestal support, and accepted for continued service without repair.

The applicant stated that another VT-3 of Salem Unit 1 was done in 2007. The inspection was performed in accordance with ASME Code Section XI, Subsection IWF and included inspection of 21 ASME Class 1, 2, and 3 component supports. The supports consist of a sample of Salem Unit 1 support types (i.e., anchor, guide, support, etc.) selected from the auxiliary feedwater, chemical volume, component cooling, containment spray, reactor coolant, residual heat removal, main steam, safety injection, and service water systems. The supports were inspected for degradation including corrosion, distortion, spring hanger functionality and settings, loose bolts and nuts, debris, and foreign material. Qualified VT-3 examiners observed no unacceptable indications as documented in the inspection datasheet.

In 2006, the applicant conducted VT-3 of 5 ASME Class 1, 2, and 3 component supports in accordance with ASME Code Section XI, Subsection IWF requirements at Salem Unit 2. The supports included a sample of support types (i.e., anchor, hanger, variable support, etc.) selected from the component cooling, residual heat removal, safety injection, and main steam systems. The supports were inspected for degradation including corrosion, distortion, spring hanger functionality and settings, loose bolts and nuts, debris, and foreign material. Qualified VT-3 examiners observed no unacceptable indications.

During replacement of the Salem Unit 2 No. 22 SG in 2007, the applicant reported that two cap screws (bolts) on one of four support base plates of the SG support were found broken. Each support base plate has six 1-½-inch diameter non-tensioned high-strength bolts (minimum yield 200 kilopounds per square inch (ksi)). The base plate design incorporates slotted holes and Lubrite® plates to allow for thermal movement. The bolts had not been previously inspected because they were not accessible. A corrective action report was initiated to document and evaluate the extent and cause of the condition. Evaluation of the condition concluded that failure was caused by improper installation and was not due to age or SCC. The bolts were not aligned as required by design to allow sliding surfaces to move without loading the bolts. The improper installation introduced high thermal loads that overstressed the two bolts causing a shear failure. As a part of extent of condition determination, the remaining bolts of both Salem Unit 2 SG support base plates were inspected, but no additional broken bolts were found. All the bolts on the four base plates of each Unit 2 SG support were replaced and installed as required by design. The applicant further stated that a past operability review determined the No. 22 SG was operable with the two broken bolts. Additionally, applicability of the condition to Unit 1 SG supports was also reviewed. The review determined the condition was not applicable to Unit 1 because of design differences between Unit 1 and Unit 2.

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 and were evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.

<u>UFSAR Supplement</u>. LRA Section A.2.1.30 provides the UFSAR supplement for the ASME Section XI, Subsection IWF Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 30) to ongoing implementation of the existing ASME Section XI, Subsection IWF Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's ASME Section XI, Subsection IWF Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended 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).

3.0.3.1.18 10 CFR 50, Appendix J

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.31 describes the existing 10 CFR 50, Appendix J Program as consistent with GALL AMP XI.S4, "10 CFR Part 50, Appendix J." The LRA further states that the program assures leakage through the primary containment and systems and components penetrating primary containment do not exceed

allowable leakage rate limits in the TSs. The applicant further stated that the program does not prevent degradation but provides measures for monitoring to detect degradation prior to the loss of intended function. Salem is implementing Option B of the program, which allows the testing intervals to be performance-based.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S4. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.S4. Based on its audit, the staff finds that elements one through six of the applicant's 10 CFR 50, Appendix J Program are consistent with the corresponding program elements of GALL AMP XI.S4 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.31 summarizes operating experience related to the 10 CFR 50, Appendix J Program. The applicant provided the results of the most recent Type A ILRTs for both units. The Salem Unit 1 containment ILRT, conducted in May 2001, was performed at a pressure that slightly exceeded containment design pressure as listed in the Salem UFSAR. This Unit 1 slight overpressure was due to a procedure error that was not picked up during the peer reviews. During the audit, the applicant provided documentation indicating no evidence of any structural damage that had been reported during subsequent ASME Section Code XI, Subsections IWE and IWL inspections. The applicant provided documentation stating that a notification was initiated to change the procedure. The due date for this change was January 18, 2007. The next ILRT is not scheduled to be performed on Salem Unit 1 until 2011. The applicant also stated that Type B and C test failures have been noted due to debris and general degradation of valve seating surfaces, which have been corrected where necessary by cleaning or adjusting the connecting components. For example, at Salem 2, the results of a local leakage rate test performed in October 2003 for an outboard isolation valve exceeded the allowable administrative TS limits. The valve was investigated and repaired to resolve the condition. At Salem 1 in April 2001, the primary water supply to the pressurizer relief tank isolation valve was leak rate tested and found to exceed the allowable TS limits. The cause of the failure was due to the leak-through of an adjacent valve resulting in the test failure. The adjacent valve was reworked and the retest was performed satisfactorily. The extent of the condition was reviewed to determine if other failures could result from similar circumstances.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. 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.2.1.31 provides the UFSAR supplement for the 10 CFR 50, Appendix J Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 31) to ongoing implementation of the existing 10 CFR 50, Appendix J Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's 10 CFR 50, Appendix J Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.19 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. LRA Section B.2.1.35 describes the existing Protective Coating Monitoring and Maintenance Program as consistent with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The applicant stated that the program manages cracking, blistering, flaking, peeling, and delamination of Service Level I coatings subjected to indoor air in the containment structure. The applicant's definition of Service Level I coatings, coatings used in areas in the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown, is consistent with the definition of Service Level I coating defined in RG 1.54, Revision 1.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S8. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.S8. Based on its audit, the staff finds that elements one through six of the applicant's Protective Coating Monitoring and Maintenance Program are consistent with the corresponding program elements of GALL AMP XI.S8 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.35 summarizes operating experience related to the Protective Coating Monitoring and Maintenance Program. The applicant included the following as part of the operating experience:

> In 2008, an inspection of the Salem Unit 1 containment coatings was conducted during the refueling outage. The inspection was conducted in accordance with the Protective Coating Monitoring and Maintenance Program. Pre-walkdown research was completed per the program requirements. While the inspections covered the accessible areas of the 78-ft, 100-ft, and 130-ft elevations of the containment structure outer annulus and in the bioshield, the first focused inspections were performed at areas inspected in the previous outage, and identified for continued monitoring. These areas consisted of missing coatings on the outer bioshield wall from previous efforts of removing delaminations to sound coatings, missing coatings on structural steel due to mechanical damage, and missing coatings on structural steel due to mechanical damage, and missing coatings on the concrete floor due to mechanical damage. Missing coatings identified in the previous outage and re-inspected in the 2008 outage did not exhibit any further degradation and were considered satisfactory for the next cycle. The 2008 inspection findings indicated that the coatings applied to metal and concrete surfaces were in satisfactory condition except for two specific areas that required immediate attention in the current outage. These two areas were documented in the corrective action program and after discussions with station management on the priority for immediate corrective action, repairs were made to these areas within the current outage. This example provides objective evidence that the Protective Coating Monitoring and Maintenance Program is effective in monitoring the conditions of coatings, identifying areas of degraded conditions, recommending and communicating appropriate corrective actions, and restoring the degraded coatings to a satisfactory condition.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would be ineffective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.

<u>UFSAR Supplement</u>. LRA Section A.2.1.35 provides the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed to ongoing implementation of the existing Protective Coating Monitoring and Maintenance Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Protective Coating Monitoring and Maintenance Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(2). 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 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.36 describes the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages embrittlement, cracking, swelling, surface contamination, or discoloration to ensure that electrical cables, connections, and terminal blocks not subject to the EQ requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended functions.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E1. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.E1. Based on its audit, the staff finds that elements one through six of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are consistent with the corresponding program elements of GALL AMP XI.E1 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.36 summarizes operating experience related to the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that, in October 2003, mechanical technicians observed deteriorated insulation on the 230-volt (V) cable that powers the Salem containment sump pumps. The degradation was local to the sump lid penetration and appeared to be caused by jacket embrittlement and excessive stress on the cable. The repairs to the cable insulation and jacket were made before any loss of function of the containment sump pumps was detected.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. 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.2.1.36 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff also notes that the applicant committed (Commitment No. 36) to implement the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.21 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Summary of Technical Information in the Application. LRA Section B.2.1.37 describes the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program as consistent with GALL AMP XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The applicant stated that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program manages the in-scope portions of the radiation monitoring system and the reactor protection system (i.e., the nuclear instrumentation system) not included in the Salem EQ program. This program applies to sensitive instrumentation cable and connection circuits with low-level signals that are within the scope of license renewal and are located in areas where the cables and connections could be exposed to adverse localized environments caused by heat, radiation, or moisture.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E2. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.E2. Based on its audit, the staff finds that elements one through six of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program are consistent with the corresponding program elements of GALL AMP XI.E2 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.37 summarizes operating experience related to the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. The applicant stated that, in December 2006, a routine surveillance of the Salem Unit 1 plant vent noble gas radiation monitor revealed a broken background detector connector. The entire detector was later replaced. The extent of the condition review revealed no other problem with the plant vent noble gas radiation monitor. The applicant also stated that, in August 2006, an investigation was initiated because the Salem Unit 1 12 SGBD radiation monitor background activity increased to above normal expected levels, although the background activity levels were still well below the alarm setpoint. The radiation monitor passed its channel source check. Further troubleshooting discovered that the cable connector between the rate meter and the pre-amp had begun to fail. The cable and connector were replaced and the system was retested to satisfactory.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. 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.2.1.37 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff also notes that the applicant committed (Commitment No. 37) to implement the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.22 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.38 describes the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL AMP XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that its program manages inaccessible medium voltage cables that are exposed to significant moisture simultaneously with significant voltage. The applicant stated that significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable in standing water). The applicant also stated that significant voltage exposure is defined as being subject to system voltage for more than 25 percent of the time. The applicant further stated that in-scope, non-EQ, inaccessible medium voltage cable subject to significant moisture and voltage will be tested as part of this AMP. The applicant stated that these medium voltage cables will be tested using a test that is capable of detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index or other testing that is state-of-the-art at the time the test is performed. The applicant also stated that cable testing will be performed at least once every 10 years. The applicant further stated that the first tests will be completed prior to the period of extended operation.

The applicant stated that manholes and cable vaults will be inspected for water collection and in-scope, non-EQ, inaccessible cables subject to significant moisture and voltage will be evaluated, so that draining or other corrective actions can be taken. The applicant also stated that the frequency of manhole and cable vault inspections for accumulated water and subsequent pumping will be based on existing practices and adjusted based on inspection results. Further, the applicant stated that the maximum time between inspections will be no more than 2 years with the first inspections completed prior to 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 also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E3. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.E3. Based on its audit, the staff finds that elements one through six of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are consistent with the corresponding program elements of GALL AMP XI.E3 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.38 summarizes operating experience related to the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental

Qualification Requirements Program. The applicant stated its program is a new program, which will adequately manage the localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion and water trees. The applicant further stated that in response to GL 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," dated May 7, 2007, and December 12, 2007, Salem has no history of failures of inaccessible or underground medium voltage cables. The scope of this review included AC power cables rated 230 VAC to 15,000 VAC.

The LRA provided examples of operating experience that the applicant stated provided objective evidence that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be effective in assuring that intended functions will be maintained consistent with the CLB for the period of extended operation. One example was the inspection of manhole SWI-1 for the service water pump 4-kilovolt (kV) cable pull vaults performed in 2003 in response to NRC IN 2002-12. The applicant's inspection found the vault generally dry with some amount of water on the floor. The cables were not submerged. The applicant stated that this manhole has a drain installed which leads to the service water pipe tunnel sump. In June 2009, the applicant re-inspected the manhole associated with service water medium voltage cables (SWI-1) with no cable submergence noted. During the audit, the staff confirmed the applicant's inspection findings through document reviews including pictures taken during both the 2003 and 2009 applicant inspections. A second example was the detection, in May 2004, of groundwater leakage that deteriorated the flexible conduit containing service water pump 4-kV cables into the auxiliary building. This deterioration was repaired. A third example was the testing performed, in May 2003, on a cable for the T2-T4 crosstie (13.8 kV), in order to enable use of the crosstie cable during the refueling outage. This testing successfully detected a leakage current that led to cable repair. Finally, in March 2001, inspection and testing of the 4-kV power cable for the 12B circulating water pump motor identified a defective cable splice. Based on these examples, the applicant stated that: (1) detection methods exist to identify aging effects and prevent the loss of intended function, (2) issues found were addressed and documented using the corrective action program, and (3) industry operating experience will be used to improve the program such that if any aging effects do occur, they would be detected prior to 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 Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the period 2000 through November 2009. Databases were searched using various keyword searches and then reviewed by technical auditor staff.

During its review, the staff identified operating experience which could indicate that the applicant's program may not be effective in adequately managing aging effects during the period of extended operation. The staff also interviewed applicant personnel and reviewed documentation for in-scope medium voltage inaccessible cables associated with station blackout (SBO) to determine whether these cables were also subject to submergence. The applicant identified operating experience of inaccessible medium voltage cable exposure to significant moisture. A review of LRA Section B.2.1.38 and the applicant's basis document did not provide operating experience for in-scope, inaccessible medium voltage SBO recovery cable testing or manhole/vault inspection results. Based on the above, the staff was concerned that the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49

Environmental Qualification Requirements Program may not be effective in adequately managing aging effects during the period of extended operation. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

By letter dated June 10, 2010, the staff issued RAI B.2.1.38-1 requesting that the applicant describe how LRA Section B.2.1.38 meets GALL AMP XI.E3 for in-scope, inaccessible medium voltage SBO recovery cables considering plant operating experience shows in-scope inaccessible medium voltage cables are exposed to significant moisture for significant periods of time (more than a few days). The staff also requested that the applicant:

> Describe how plant operating experience was incorporated into AMP B.2.1.38 to minimize exposure of in-scope, inaccessible medium voltage SBO recovery cables to significant moisture during the period of extended operation; discuss corrective actions taken that address submerged cable conditions identified through manhole/vault inspections; and discuss cable testing frequency and applicability that demonstrate in-scope inaccessible medium voltage SBO recovery cable[s] will continue to perform their intended function during the period of extended operation.

The applicant responded by letters dated July 8, 2010, and August 26, 2010, and stated:

> Salem LRA Appendix B, Section B.2.1.38-"Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," is a new program that is currently in the process of being implemented at Salem. This program includes (1) testing of in-scope, inaccessible medium voltage cables subject to significant moisture and significant voltage and (2) inspection of cable manholes, including pumping of accumulated water, if required, as a preventive measure to minimize the potential exposure of in-scope cables to significant moisture. There is no direct buried medium voltage cable in-scope for license renewal.

The applicant also stated that, prior to the period of extended operation, additional SBO recovery cable manhole and cable pit inspections will be performed and the frequency of inspections for accumulated water will be adjusted based on inspection results to ensure that the in-scope SBO recovery cables are not exposed to significant moisture. The applicant further stated that the maximum time between inspections for accumulated water will be no longer than 2 years, which meets the recommended frequency in GALL AMP XI.E3.

The applicant stated that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program meets GALL AMP XI.E3 for the in-scope SBO recovery cables because prior to the period of extended operation, cable tests will be periodically performed (not to exceed 10 years) and prior to the period of extended operation, the frequency of inspections for accumulated water will be established (not to exceed 2 years) based on inspection results to ensure that the in-scope SBO recovery cables are not exposed to significant moisture during the period of extended operation.

The applicant stated that there are 8 manholes and 13 cable pits where in-scope medium voltage SBO recovery cables can be inspected for water submergence. The applicant also stated that all 8 manholes were inspected in March 2010. The inspections found submerged cables; the manholes were subsequently dewatered. The condition was entered into the applicant's corrective action program. The applicant did not identify cable defects or concrete conditions adverse to quality as a result of the manhole inspections. The applicant did state that the cover and cover support steel for manhole MH-1 and MH-1A were found rusted but no structural degradation was noted. The applicant also stated that the cover and cover support structure were entered into the applicant's corrective action program with repairs planned for May 2011.

LRA Section B.2.1.38 and the responses to GL 2007-01 did not identify failures of in-scope inaccessible medium voltage cables. The applicant stated that it plans to test the SBO recovery cables every 3 years during station power transformer outages, with the first tests planned for April 2011. The applicant also stated that testing will continue to be conducted periodically in order to trend and characterize the SBO recovery cable insulation. The applicant further stated that the cable test frequency may be adjusted based on data trending, but the cable test frequency will not exceed 10 years.

The applicant revised LRA Section B.2.1.38 and Section A.2.1.38 to clarify inspection and test frequencies and implementation of cable testing and inspection programs, to incorporate the RAI responses and provide consistency with GALL AMP XI.E3. The applicant also revised the LRA Table A.5 Commitment List, Item 38 to specifically include manhole and cable vault inspections.

The GALL Report addresses inaccessible medium-voltage cables in GALL AMP XI.E3. The purpose of this program is to provide reasonable assurance that the intended functions of inaccessible medium-voltage cables (2 kV to 35 kV) that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized, will be maintained consistent with the CLB. The application of GALL AMP XI.E3 to medium-voltage cables by the applicant was based on the operating experience available at the time the GALL Report, Revision 1 was developed. However, recently identified industry operating experience indicates that the presence of water or moisture can be a contributing factor in inaccessible power cable failures at lower operating voltages (480 V to 2 kV). Applicable operating experience was identified in licensee responses to GL 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which included failures of power cable operating at service voltages of less than 2 kV where water was considered a contributing factor. The staff has concluded, based on recently identified industry operating experience concerning the failure of inaccessible low voltage power cables (480 V to 2 kV) in the presence of significant moisture, that these cables may potentially experience age degradation.

The staff was also concerned that recent industry operating experience also shows an increasing trend in cable failures with a length of service beginning in the 6th through 10th years of operation. In addition, recently identified industry operating experience has shown that some NRC licensees may experience events, such as flooding or heavy rain, that subject cables within the scope of the program for GALL AMP XI.E3 to significant moisture. The staff noted that the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program did not address inaccessible low voltage power cables.

By teleconference dated August 16, 2010, and by letter dated September 7, 2010, the staff discussed with the applicant the cable test and manhole/vault inspection frequencies and the inclusion of inaccessible low voltage cables into the scope of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program based on recent industry operating experience. During the conference call, the applicant noted that Salem has no low voltage power cables (480 V to 2 kV) exposed to significant moisture. The applicant stated that the only power cables exposed to significant moisture and within the scope of license renewal are 13.8-kV, 4,160-V, and 230-V power cables. The applicant stated it would provide this assessment and LRA supplement to revise the Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program test and inspection frequencies to 6 years and 1 year, respectively. The applicant also agreed to revise the program to include event driven inspections and to clarify that no medium-voltage cables were excluded from the program due to the "significant voltage" criterion.

By letter dated October 7, 2010, the applicant supplemented LRA Appendix A, Section A.2.1.38, Item A.5, Item 38 and Appendix B, Section B.2.1.38 to revise cable testing and cable vault inspection criteria for the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program and stated the following:

> The only power cables exposed to significant moisture that are associated with systems in-scope for license renewal are 13,800 volt, 4,160 volt and 230 volt cables. Specifically, station blackout (SBO) recovery power is 13,800 volts and 4160 volts, and the service water pump motor power is 4,160 volts. The auxiliary power to the Salem service water intake structure auxiliary loads is 230 volts. Therefore, as discussed with the NRC staff in reference 3, [teleconference dated August 16, 2010] there is no change in the Salem Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP scope, as the SBO recovery and service water pump motor cables are already included within the scope of the E3 [Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements] program.
>
> Although Salem does have a 460V system within scope for license renewal, the in-scope portions of the 460V distribution system do not go underground nor are there any in-scope portions of the 460V system exposed to significant moisture. Therefore the 460V cable is not subject to the E3 program. However, the 460V system has already appropriately been included within the scope of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (E1) Program.

The applicant also stated that no inaccessible power cable exposed to significant moisture was excluded from the program due to the "significant voltage" criterion. In addition, the applicant stated there have been no underground or inaccessible low voltage power cable failures at Salem, including 230-V power cables. The applicant also stated that the cable test frequency will be established based on test results and industry operating experience with the maximum time between tests no longer than 6 years. Further, the applicant stated that the frequency of inspections for accumulated water will be established based on inspection results and that station procedures will direct the assessment of the cable condition as a result of rain or other event-driven occurrences. Finally, the applicant stated that as a limit on the time between inspections, the maximum time between inspections will be no more than 1 year.

Based on the information provided by the applicant's response to RAI B.2.1.38-1 and the LRA supplement dated October 7, 2010, the staff finds that:

(a) The applicant has appropriately evaluated the program scope with respect to inaccessible low voltage cables (480 V to 2 kV) and eliminated the criterion of "exposure to significant voltage," consistent with industry operating experience.

(b) For Salem, the proposed 6-year test frequency for power cable insulation testing is appropriate for the following reasons identified in the applicant's RAI response and LRA supplement: (1) the applicant has not identified any underground or inaccessible low voltage power cable failures at Salem; (2) inaccessible power cables within scope of the program have, however, experienced exposure to significant moisture including submergence; (3) the frequency of testing may be increased based on test results and operating experience. This approach is consistent with the discussion of operating experience in the SRP-LR, which states that applicants should consider future plant-specific and applicable industry operating experience for its AMPS.

(c) The applicant's proposed approach to inspecting manhole and cable vaults containing inaccessible in-scope power cables is appropriate based on the plant-specific operating experience at Salem. For example, the applicant has established recurring tasks to open, inspect, and dewater manholes, cable vaults, and cable pits, as required, to monitor the in-scope service water and SBO cables. The staff notes that the applicant's inspection plans for water accumulation are designed to optimize the inspection frequency such that: (1) in-scope inaccessible power cables are not exposed to significant moisture, and (2) cable condition assessment as a result of rain or other event-driven occurrences is included. However, at a minimum, the applicant has established a maximum time between inspections of 1 year. Given that plant-specific operating experience has identified cables exposed to significant moisture, an increased inspection frequency with provisions to address event-based occurrences is acceptable, provided the applicant's approach to establish the optimum frequency will continue to inform the program's periodicity (i.e., provide feedback for changes of the inspection periodicity as appropriate).

The staff finds that, with the enhancements provided in the applicant's LRA supplement and the information provided by the applicant's response to RAI B.2.1.38-1, the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will adequately manage the aging effects of inaccessible power cables, consistent with industry operating experience. The staff finds the program acceptable because the applicant has revised LRA Section A.2.1.38, Section A.5, and Section B.2.1.38 consistent with the guidance of SRP-LR Section A.1.2.3.10 and GALL AMP XI.E3, such that there is reasonable assurance that inaccessible medium voltage cables subject to significant moisture will be adequately managed during the period of extended operation. The staff's concern described in RAI B.2.1.38-1 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B.2.1.38-1 and the LRA supplement, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program resulted in the applicant taking corrective action. The staff also verified that the aging effects are bounded by those identified in GALL AMP XI.E3 and the more recent operating experience identified in GL 2007-01.

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.2.1.38 provides the UFSAR supplement for the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.6-2.

By letter dated June 10, 2009, the staff issued RAI B.2.1.38-3 requesting that the applicant discuss why the UFSAR summary description in LRA Section A.2.1.38 does not include definitions of significant moisture and significant voltage consistent with SRP-LR Table 3.6-2 and LRA Section B.2.1.38. The applicant responded by letter dated July 8, 2010, and stated that LRA Section A.2.1.38 is revised to include these definitions. In addition, the applicant submitted an LRA supplement dated October 7, 2010, that revised LRA Section A.2.1.38 cable test and inspection frequencies and clarified the scoping of inaccessible power cables in its Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. With the information provided by the applicant's RAI response and LRA supplement dated October 7, 2010, the staff finds the UFSAR supplement acceptable because the applicant's revision is consistent with the guidance of SRP-LR Table 3.6-2. Based on the applicant's response to RAI B.2.1.38-3 and the LRA supplement, the staff's concern described in RAI B.2.1.38-3 is resolved.

The staff also notes that the applicant committed (Commitment No. 38) to implement the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.23 Metal Enclosed Bus

Summary of Technical Information in the Application. LRA Section B.2.1.39 describes the new Metal Enclosed Bus Program as consistent with GALL AMP XI.E4, "Metal Enclosed Bus." The applicant stated that the Metal Enclosed Bus Program manages the aging of in-scope metal enclosed buses within the scope of license renewal so that they are capable of performing their intended functions. The applicant also stated that internal portions of the in-scope metal enclosed bus enclosures will be visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. Furthermore, loose bolted connections will be checked by sampling using thermography from outside of the metal enclosed bus.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E4. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.E4. The staff noted that the applicant referenced two materials (aluminum and elastomer) under metal enclosed bus components to be managed by the Structures Monitoring Program. The staff reviewed and confirmed that these materials will be managed by the Structures Monitoring Program. Based on its audit, the staff finds that elements one through six of the applicant's Metal Enclosed Bus Program are consistent with the corresponding program elements of GALL AMP XI.E4 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.39 summarizes operating experience related to the Metal Enclosed Bus Program. The applicant stated that in November 1996, in response to industry experience, work orders were generated to megger and high-potential test the 4-kV non-segregated metal enclosed bus duct and inspect the duct connecting the auxiliary power transformers to the 4-kV group buses. The duct was inspected, cleaned, and in some cases caulked, principally at locations where housing bolts may have been loose on the top horizontal sections of the duct, to prevent moisture intrusion. The applicant also included enhancements to existing preventive maintenance procedures and practices to more effectively detect water intrusion and address the lessons learned from industry operating experience.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. 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.2.1.39 provides the UFSAR supplement for the Metal Enclosed Bus Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff also notes that the applicant committed (Commitment No. 39) to implement the new Metal Enclosed Bus Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Metal Enclosed Bus Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.24 Environmental Qualification (EQ) of Electric Components

Summary of Technical Information in the Application. LRA Section B.3.1.2 describes the existing Environmental Qualification (EQ) of Electric Components Program as consistent with GALL AMP X.E1, "Environmental Qualification (EQ) of Electric Components." The applicant stated that the Environmental Qualification (EQ) of Electric Components Program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations in adverse localized environments. The applicant stated that program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants." The applicant further stated that qualified life is determined for equipment within the scope of the Environmental Qualification (EQ) of Electric Components Program and appropriate actions such as replacement or refurbishment, or reanalysis are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The applicant also stated that the program ensures maintenance of the qualified life for electrical equipment within the scope of the Environmental Qualification (EQ) of Electric Components Program through the period of extended operation.

As required by 10 CFR 50.49, EQ program components not qualified for the current license term are refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluations. Aging evaluations for EQ program components are TLAAs for license renewal.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP X.E1. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP X.E1. Based on its audit, the staff finds that elements one through six of the applicant's Environmental Qualification (EQ) of Electric Components Program are consistent with the corresponding program elements of GALL AMP X.E1 and, therefore, acceptable.

Operating Experience. LRA Section B.3.1.2 summarizes operating experience related to the Environmental Qualification (EQ) of Electric Components Program. The applicant stated its program is an existing program, which implements preventive activities to ensure that the qualified life of components within the scope of the program is maintained through the period of extended operation. The applicant also stated that the effects of aging are effectively managed by objective evidence that demonstrates that aging effects and mechanisms are adequately managed.

The applicant's operating experience included improved work planning scheduling for EQ maintenance orders and improved EQ work order scheduling including improved allowances for procurement lead times and outages. The applicant stated this example demonstrates that the applicant's program identifies and incorporates corrective actions and EQ program improvement. The applicant further stated that, to evaluate EQ concerns, plant data, calculations, and the corrective action program are used, as evidenced by the applicant's revision of the EQ calculations for the centrifugal charging pumps to account for additional pump motor run time.

The staff reviewed the operating experience 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. 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.3.1.2 provides the UFSAR supplement for the Environmental Qualification (EQ) of Electric Components Program. The staff reviewed this UFSAR supplement description of the program and notes that, in conjunction with the TLAA UFSAR Section A.4.7, it conforms to the recommended description for this type of program as described in SRP-LR Tables 4.4-1 and 4.4-2.

The staff also notes that the applicant committed (Commitment No. 48) to ongoing implementation of the existing Environmental Qualification (EQ) of Electric Components Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Environmental Qualification (EQ) of Electric Components Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPS That Are Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant identified the following AMPs that were, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Flow-Accelerated Corrosion
- Bolting Integrity
- Closed-Cycle Cooling Water System
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Fire Protection
- Fire Water System
- Aboveground Steel Tanks
- Fuel Oil Chemistry
- Reactor Vessel Surveillance
- Buried Piping Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Lubricating Oil Analysis
- ASME Section XI, Subsection IWE
- Masonry Wall Program
- Structures Monitoring Program
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Fatigue of Reactor Coolant Pressure Boundary

For AMPs that the applicant claimed are consistent with the GALL Report, with exceptions or enhancements, the staff performed an audit to confirm that those attributes or features of the program for which the applicant claimed consistency with the GALL Report were indeed consistent. The staff also reviewed the exceptions and enhancements to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audit and reviews are documented in the following sections.

3.0.3.2.1 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. LRA Section B.2.1.8 describes the existing Flow-Accelerated Corrosion Program as consistent, with an exception, with GALL AMP XI.M17, “Flow-Accelerated Corrosion.” The applicant stated that the program provides for predicting, detecting, and monitoring wall thinning in piping and fittings, valve bodies, and heat exchangers due to flow-accelerated corrosion in closed-cycle cooling water, steam, and treated water environments. The applicant also stated that the program uses analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to flow-accelerated corrosion to predict the amount of wall thinning in pipes and fittings and feedwater heater shells. The applicant further stated that a predictive code called CHECWORKS is used to determine critical locations in piping and other components susceptible to flow-accelerated corrosion and that the Flow-Accelerated Corrosion Program is based on the EPRI guidelines in NSAC-202L, Revision 3, “Recommendations for an Effective Flow-Accelerated Corrosion program.”

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

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.M17. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M17.

The staff also reviewed the portions of the “scope of the program” and “detection of aging effects” program elements associated with the exception to determine whether the program will be adequate to manage the aging effect for which it is credited. The staff’s evaluation of this exception follows.

Exception. LRA Section B.2.1.8 states an exception to the “scope of the program” and “detection of aging effects” program elements. GALL AMP XI.M17 recommends the use of Revision 2 of the EPRI guidance document NSAC-202L. The applicant stated that the Flow-Accelerated Corrosion Program is based on the EPRI guidelines found in NSAC-202L, Revision 3. In addition, the applicant provided justification for using Revision 3 with the following:

> The sections of NSAC-202L associated with the program elements were reviewed to show that Revision 2 and 3 of the guidelines are equivalent with one main difference: Revision 3 allows an additional method for determining the wear of piping components from UT inspection. This method is called the Average Band Method. This method is a derivation of the Band Method and builds upon the years of experience with the Band Method, which remains an option in NSAC-202L-R3 for determining the wear of piping components from UT inspection. As explained in NSAC-202L-R3, overly conservative methods, such as [the] Band Method, can lead to unnecessary inspections or re-inspections. The Average Band Method provides a more realistic estimate of piping wear than the Band Method.

The staff finds this program exception acceptable because the applicant demonstrated that NSAC-202L, Revision 3 is equivalent to Revision 2, with the exception being that Revision 3 uses methods that more appropriately characterize wear of piping components using UT inspection. The use of Revision 3 is determined to be consistent with GALL AMP XI.M17.

Based on its audit, the staff finds that program elements one through six of the applicant's Flow-Accelerated Corrosion Program, with acceptable exception, are consistent with the corresponding program elements of GALL AMP XI.M17 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.8 summarizes operating experience related to the Flow-Accelerated Corrosion Program. The applicant provided the following operating experience to demonstrate that the Flow-Accelerated Corrosion Program will be effective in assuring that intended functions would be maintained consistent with the CLB for the period of extended operation:

(1) In response to industry events OE9941 and OE9632, both in 1999, which document wall thinning in feedwater heater shells due to flow-accelerated corrosion, Salem proactively inspected a sampling of high pressure and low pressure feedwater heater shells and subsequently had to replace the Salem Unit 1 15A, B and C feedwater heater shell sections with in-kind material in the fall of 1999. Salem issued OE11020 to document the findings. At Salem Unit 2, the 25A, B and C feedwater heater shell sections were replaced with upgraded flow-accelerated corrosion resistant stainless steel clad shell sections in 2000, as a planned replacement. Additionally, during Salem Unit 1 refueling outages in 2004 and 2005, engineering follow-up evaluations of the Flow-Accelerated Corrosion Program UT data information indicated that the shell wall thickness of the 15A feedwater heater in the areas around both south and north bleed steam inlet nozzles would remain above the flow-accelerated corrosion minimum criteria through 2008, but may not meet their minimum required thickness requirements thereafter. The corrective actions for Salem Unit 1 15A, B and C feedwater heater shell sections for the areas around both bleed steam inlet nozzles involved replacing the plate Section around the nozzles with flow-accelerated corrosion resistant stainless steel cladding in 2008.

(2) UT inspections in support of the Flow-Accelerated Corrosion Program scope during the Salem Unit 1 refueling outage in 2008 identified the need to replace a 3-inch diameter pipe bend and two elbows in the moisture separator and reheater drains system going to the 16B feedwater heater. The component was selected for inspection based on CHECWORKS results. The need for replacement of this 3-inch pipe was further increased because of identification of external corrosion, whose informational UT examination identified that its thickness in this area was close to minimum wall thickness. UT data review and evaluation was performed in accordance with the Flow-Accelerated Corrosion Program procedure. Corrective actions completed as a result of the analyses of this event identified internal pipe wall thinning to be caused by flow-accelerated corrosion over the course of this component's life, whereas the external corrosion was due to a leaking boot in the roof penetration directly above the subject bend. This Section of the pipe, including a 3-inch diameter pipe bend and two elbows, which were made of carbon steel, were replaced with upgraded flow-accelerated corrosion resistant chromium-molybdenum components during the Salem Unit 1 refueling outage in 2008.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would be ineffective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.8 provides the UFSAR supplement for the Flow-Accelerated Corrosion Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, and 3.4-2.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion 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 exception, is adequate to manage the aging effects for which the LRA credits it. 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 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B.2.1.9 describes the existing Bolting Integrity Program as consistent, with an exception and an enhancement, with GALL AMP XI.M18, "Bolting Integrity." The applicant stated that the Bolting Integrity Program incorporates NRC and industry recommendations delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants"; EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide"; and EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants." The applicant also stated that the Bolting Integrity Program provides for condition monitoring of pressure-retaining bolting within the scope of license renewal and that the program provides for managing cracking, loss of material, and loss of preload by performing visual inspections for pressure-retaining bolted joint leakage in environments of air, raw water, and soil. The applicant further stated that procurement controls and installation practices defined in plant procedures ensure that only approved lubricants, sealants, and proper torques are applied to bolting within the scope of the program and that the activities are implemented through station procedures.

The applicant stated that: (1) for ASME Code class bolting, the extent and schedule of inspections is in accordance with ASME Code Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1; (2) bolting associated with ASME Code Class 1 vessel, valve, and pump flanged joints receive VT-1 inspection; and (3) for other pressure-retaining bolting, routine observations will document any leakage before the leakage becomes excessive. The applicant also stated that the integrity of non-ASME Class 1, 2, and 3 system and component pressure-retaining bolted joints is evaluated by detection of visible leakage during maintenance or routine observation such as system walkdowns. The applicant further stated that: (1) high-strength bolting material with actual yield strength greater than or equal to 150 ksi is used for nuclear steam supply system (NSSS) Class 1 component supports, but that the bolts are installed in sliding connections with no preload to allow for thermal movement; and (2) an AMR determined that SCC is not an applicable aging effect or mechanism because the bolts are not subject to high sustained tensile stress. The applicant identified that the following AMPs supplement the aging management of bolting and fasteners: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; (2) ASME Section XI, Subsection IWE Program; (3) ASME Section XI, Subsection IWF Program; (4) Structures Monitoring Program; (5) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program; (6) External Surfaces Monitoring Program; (7) Buried Piping Inspection Program; and (7) Buried Non-Steel Piping Inspection Program.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M18. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding elements of GALL AMP XI.M18, with the exception of the "scope of the program" and "preventive actions" program elements. For these elements, the staff determined the need for additional clarification that resulted in the issuance of RAIs, which are discussed below.

In GALL AMP XI.M18, the "scope of the program" program element states that the Bolting Integrity Program covers bolting within the scope of license renewal, including: (1) safety-related bolting; (2) bolting for NSSS component supports; (3) bolting for other pressure-retaining components, including nonsafety-related bolting; and (4) structural bolting (actual measured yield strength greater than or equal to 150 ksi). The "preventive actions" program element states that preventive actions include proper torquing and application of an appropriate preload. Based on its review of the applicant's documentation, the staff noted that aging of component support and structural bolting within the scope of license renewal may not be managed by the applicant's Bolting Integrity Program but may instead be managed by other AMPs such as the applicant's Structures Monitoring Program. It was not clear to the staff how the applicant would ensure that all elements of GALL AMP XI.M18 would be included in other AMPs credited to manage bolting not included in the Bolting Integrity Program.

By letter dated June 10, 2010, the staff issued RAI B.2.1.9-01 requesting that the applicant explain: (1) why use of other AMPs to manage the aging effects of component support and structural bolting was not identified as an exception to the GALL AMP XI.M18 "scope of the program" program element and (2) how it ensures that other AMPs credited for aging management of component support and structural bolting include the recommendations that are contained in the GALL AMP XI.M18 "preventive actions" program element.

In its response dated July 8, 2010, the applicant confirmed its understanding that GALL AMP XI.M18 recommends that component support bolting and structural bolting be included within the scope of the Bolting Integrity Program and that the 10 elements of GALL AMP XI.M18 are applicable to component support bolting and structural bolting within the scope of license renewal. The applicant stated that it did not identify an exception to recommendations in the GALL Report because the recommendations identified in the 10 elements of GALL AMP XI.M18 are implemented through existing station procedures in its Bolting Integrity Program that are applicable to mechanical system closure bolting, as well as to component support bolting and structural bolting. The applicant also stated that additional AMPs credited for aging management of component support bolting and structural bolting are primarily condition monitoring programs that supplement activities of the Bolting Integrity Program. The applicant further stated that to ensure continued implementation of all 10 elements of its Bolting Integrity Program through the period of extended operation, the LRA is revised to credit the Bolting Integrity Program for component support bolting and structural bolting in the cranes and hoists system, the fuel handling and fuel storage system, the auxiliary building, the component supports commodity group, the containment structure, the fire pump house, the fuel handling building, office buildings, the penetration areas, the pipe tunnel, SBO yard buildings, service building, service water accumulator enclosures, service water intake, switchyard, turbine building, and yard structures.

In its response, the applicant provided a number of LRA changes which revised LRA Section A.2.1.9, the UFSAR supplement for the Bolting Integrity Program, and LRA Section B.2.1.9, the summary description for the Bolting Integrity Program, to describe the applicant's Bolting Integrity Program as "an existing program that provides aging management of pressure retaining bolted joints, component support bolting and structural bolting within the scope of license renewal." The applicant also revised or added a number of bolting-related lines in the Summary of Aging Management Evaluations tables in LRA Section 3. In the overall summary tables for each LRA subsection, the discussion for bolting components was revised to state that the Bolting Integrity Program manages aging effects in component support bolting and structural bolting and that other applicable AMPs include condition monitoring that supplements the Bolting Integrity Program. In summary tables for individual systems where the AMR result lines cited generic note E and credited some alternative to the AMP recommended in the GALL Report, the applicant added new, companion line items that credit the Bolting Integrity Program to manage the subject aging effect. For component, material, environment, and aging effect combinations that are documented in the GALL Report, the added lines are consistent with the GALL Report recommendations and cite generic note B.

In its review of the applicant's RAI response, the staff determined that including component support and structural bolting within the scope of other programs does not constitute an exception to the GALL Report because station procedures referenced in the applicant's Bolting Integrity Program that are applicable to mechanical system closure bolting are also applicable for component support bolting and structural bolting. The staff also determined that the applicant's changes to the LRA are acceptable because they clarify that alternative condition monitoring AMPs are not used in lieu of, but rather are used to supplement the mitigation and monitoring elements of the Bolting Integrity Program. The staff finds the applicant's Bolting Integrity Program to be consistent with the recommendations in GALL AMP XI.M18 with regard to the staff's concerns expressed in RAI B.2.1.9-01 and that the applicant's response resolves all issues documented in the RAI.

By letter dated May 24, 2010, the staff issued RAI 3.3.2.3.4-1, related both to the applicant's Buried Piping Inspection Program and the Bolting Integrity Program. The RAI requested that the applicant provide additional details regarding how bolting in buried piping is inspected. In its response dated June 14, 2010, the applicant stated that buried bolts are inspected during directed or opportunistic excavations of buried piping in accordance with its Buried Piping Inspection Program. In addition, a flow test is performed, as required by ASME Code

Section XI, to confirm that there is no significant leakage from buried pressure-retaining pipe joints. In its evaluation of the Bolting Integrity Program, the staff finds the applicant's response to RAI 3.3.2.3.4-1 acceptable because the applicant: (1) includes provisions for inspection of buried pressure-retaining bolting in its Buried Piping Inspection Program and (2) uses periodic flow tests to confirm that unacceptable leakage from buried, pressure-retaining bolted pipe joints does not occur. The staff's evaluation of the RAI response is documented in SER Section 3.3.2.3.4.

By letter dated August 3, 2010, the staff issued RAI B.2.1.9-02 requesting that the applicant: (1) clarify what pressure joint bolting within the scope of the Bolting Integrity Program is exposed to raw water or treated borated water environments and (2) explain how visual inspections are performed to detect loss of preload for submerged bolted joints. In its response dated August 26, 2010, the applicant stated that the pressure-retaining bolted joints exposed to raw water are limited to the service water pump bolting and that the submerged portion of the service water pumps includes bolted joints using stainless steel bolting material. The applicant further stated that the only in-scope bolting exposed to a treated borated water environment is structural bolting in the fuel handling and fuel storage system. The applicant stated that it has no pressure-retaining bolted joints within the scope of license renewal for which the bolting is exposed to a treated borated water environment.

The applicant stated that service water pump bolting is inspected during performance of the periodic service water pump inspection and repair procedure which is performed on a frequency of once every 6 years. The applicant further stated that during disassembly, the pumps are inspected for loose or missing bolting and the bolts are inspected for loss of material, and during reassembly, the bolting is torqued in accordance with design specifications to prevent loss of preload.

In its response to RAI B.2.1.9-02, the applicant submitted changes that provide additional details in LRA Sections A.2.1.9 and B.2.1.9, the UFSAR supplement, and the program evaluation for the Bolting Integrity Program. In both LRA sections, the changes add a statement that the aging management activities directed by the Bolting Integrity Program include visual inspections for pressure-retaining bolted joint leakage and preventive measures implemented during bolted joint maintenance and installation. In addition, in LRA Section B.2.1.9, the applicant added statements that normally inaccessible bolted connections are inspected for degradation when they are made accessible during maintenance activities and that inspection activities for submerged bolting are performed in conjunction with associated component maintenance activities. The applicant also stated that during review of information related to the RAI, it noted incorrect AMR lines in Table 3.3.2-23 for carbon steel and low-alloy steel bolting exposed to raw water in the service water system. The applicant stated that it has determined that this bolting is not within the scope of license renewal, and the applicant provided corrections to Table 3.3.2-23 that deleted two AMR lines related to carbon and low-alloy steel bolting exposed to raw water in the service water system.

The staff notes the applicant's clarification stating that there is no in-scope pressure joint bolting submerged in an environment of treated borated water. The staff further notes that the applicant's aging management activities for all submerged bolting within the scope of license renewal includes inspection of the submerged bolts and bolted joints on a frequency determined by periodic maintenance or inspection of associated components. The staff finds this feature of the Bolting Integrity Program acceptable because periodic inspections provide opportunity for the applicant to find, evaluate, and correct any degraded conditions associated with submerged bolting before failure of the bolting to perform its intended function occurs. The staff also finds the applicant's changes to the LRA acceptable because they provide additional detail and clarification describing implementation of the Bolting Integrity Program and correct a previously unidentified misstatement in the LRA. On this basis, the staff finds that the applicant's response to RAI B.2.1.9-02 resolves all issues addressed in the RAI.

The staff also reviewed the portions of the "monitoring and trending" and the "corrective actions" program elements associated with the exception and the 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 exception and enhancement follows.

Exception. LRA Section B.2.1.9 states an exception to the "monitoring and trending" program element. The applicant stated that the GALL Report indicates that if a bolting connection for a pressure-retaining component (not covered by ASME Code Section XI) is reported to be leaking, then it may be inspected daily and that if the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly. The applicant stated that it uses its corrective action program to determine an appropriate inspection frequency for identified leaks in bolting connections.

The applicant provided justification for this exception by stating that for other than ASME Class 1, 2, or 3 bolting, it uses its corrective action program to document and manage locations where leakage is identified during routine observations, including engineering walkdowns and equipment maintenance activities. The applicant also stated that based on the severity of the leak and the potential to impact plant operations and nuclear or industrial safety, a leak will be repaired immediately, scheduled for repair, or monitored for change. The applicant further stated that if the leak rate changes (increases, decreases, or stops), the monitoring frequency is re-evaluated and may be revised and that its operating experience has not indicated a need for a set frequency (e.g., daily) of leakage inspections involving bolting.

The staff noted that the applicant's corrective action program is consistent with the requirements of 10 CFR Part 50, Appendix B and includes provisions for reporting, documenting, evaluating safety significance, trending, and implementing corrective actions for bolted pressure boundary components reported to be leaking. Because the applicant's corrective action program is consistent with 10 CFR Part 50, Appendix B and has provisions to determine an appropriate inspection frequency for a bolted pressure boundary component found to be leaking, the staff finds the applicant's exception to be acceptable.

Enhancement. LRA Section B.2.1.9 states an enhancement to the "corrective actions" program element. The applicant stated that prior to the period of extended operation, the "corrective actions" program element will be revised to state that the following bolts and nuts should not be reused: (1) galvanized bolts and nuts, (2) American Society for Testing and Materials (ASTM) A490 bolts, and (3) any bolts and nuts tightened by the turn of nut method.

The staff noted that the applicant's enhancement to its Bolting Integrity Program is listed as Commitment No. 12 in LRA Table A.5, "License Renewal Commitment List." The staff also noted that the applicant's proposed enhancement is consistent with EPRI TR-104213, Section 16.11.2, which provides recommendations regarding bolting material that should not be reused. On the basis that guidelines of EPRI TR-104213 are endorsed by GALL AMP XI.M18 and the applicant's enhancement is consistent with a recommendation in the EPRI guidance document and is listed in the applicant's license renewal commitment list, the staff finds the applicant's enhancement to its Bolting Integrity Program to be acceptable.

Based on its audit and review of the applicant's response to RAI B.2.1.9-01, the staff finds that elements one through six of the applicant's Bolting Integrity program, with an acceptable exception and an enhancement, are consistent with the corresponding program elements of GALL AMP XI.M18 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.9 summarizes operating experience related to the Bolting Integrity Program. The applicant stated that it has experienced isolated cases of bolt corrosion, loss of bolt preload, and bolt torquing issues and that in all cases, the existing inspection and testing methodologies have discovered the deficiencies and corrective actions were implemented prior to loss of system or component intended functions. In one operating experience example, the applicant stated that during an 89-13 inspection of the safety injection pump lube oil cooler, all eight studs on one of the heat exchanger end bells were found to be corroded and required replacement. The applicant also stated that the failure was caused by corrosion due to service water leaking onto the carbon steel end bell bolting and that the carbon steel bolting in contact with the titanium tubesheet and the 316 stainless steel end bell caused a severe galvanic cell when it became wetted from service water leakage. The applicant further stated that the corroded studs were replaced in-kind and that the integrity of the bolts is controlled through proper maintenance and regular inspection.

In another operating experience example, the applicant stated that an evaluation of the torque procedure and resulting gasket preload was performed to determine whether this was the cause of leaks that occurred at the plant which identified that a change in gasket design, from asbestos to non-asbestos replacement gaskets, was the cause of the failure because the non-asbestos gaskets require higher seating stresses to obtain an adequate seal. The applicant also stated that action was taken to incorporate EPRI bolting practices into the applicable procedures and the bolt torquing procedure was revised. The applicant further stated that these examples demonstrate that problems are discovered before intended function is affected and that corrective actions are taken to prevent recurrence.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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 of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.9 provides the UFSAR supplement for the Bolting Integrity Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 9) to enhance the Bolting Integrity Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the Bolting Integrity

Program prior to the period of extended operation to include a requirement that the following bolts and nuts should not be reused: (1) galvanized bolts and nuts, (2) ASTM A490 bolts, and (3) any bolts and nuts tightened by the turn of nut method.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Bolting Integrity 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 aging effects for which the LRA credits it. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 9 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it is compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Closed-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B.2.1.12 describes the existing Closed-Cycle Cooling Water System Program as consistent, with an exception and enhancements, with GALL AMP XI.M21, "Closed-Cycle Cooling Water System." The applicant stated that the Closed-Cycle Cooling Water System Program manages the aging of piping, piping components, piping elements, and heat exchangers for cracking, loss of material, and reduction in heat transfer due to fouling. The applicant stated that the program uses chemistry guidelines based on EPRI TR-1007820 for corrosion inhibitors, water purity to mitigate corrosion, and inspections and NDEs for monitoring heat exchanger performance. The applicant also stated that the program trends the performance of system pumps and heat exchangers to identify corrective actions and indicated that a one-time inspection will be performed in low flow areas to verify the effectiveness of the Closed-Cycle Cooling Water System Program in mitigating aging effects in these areas.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M21. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M21.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements associated with an 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.2.1.12 states an exception to the “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that it will implement the guidance provided in EPRI TR-1007820, which is the 2004 revision to EPRI TR-107396, whereas the GALL Report cites the 1997 revision of EPRI TR-107396. The applicant also stated that the new revision provides more prescriptive guidance, has a more conservative monitoring approach, and meets the same requirements of EPRI TR-107396 for effectively managing loss of material, cracking, and reduction of heat transfer.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because the EPRI closed cooling water chemistry guidelines had been updated from the version cited in the GALL Report. The staff finds this exception acceptable because the newer version of the above EPRI guidelines contains more recent operating experience information and applies a more conservative approach to managing aging than the previous version.

Enhancement 1. LRA Section B.2.1.12 states an enhancement to the “preventive actions,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that, since the component cooling system is not currently analyzed for sulfates, which is not consistent with the EPRI standard, the program will be enhanced to include monitoring for this parameter.

During the onsite audit, the staff interviewed Salem technical staff which indicated that the applicant would analyze the component cooling system for sulfates and that the frequency, method of sampling, and analysis would be consistent with EPRI guidance. On the basis of this review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and the applicant’s program will be consistent with the recommendations in GALL AMP XI.M21, after the enhancement is implemented.

Enhancement 2. LRA Section B.2.1.12 states an enhancement to the “preventive actions,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that, since the EDG jacket water system is not currently analyzed for azole or ammonia, chlorides, fluorides, and microbiologically-influenced corrosion (MIC) in accordance with the current EPRI standard, the program will be enhanced to include monitoring for these parameters.

During the onsite audit, the staff interviewed Salem technical staff which indicated that the applicant would analyze the EDG jacket water system for the parameters noted above and that the frequency, method of sampling, and analyses and inspections would be consistent with EPRI guidance. On the basis of its review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and after the enhancement is implemented, the applicant’s program will be consistent with recommendations in GALL AMP XI.M21.

Enhancement 3. LRA Section B.2.1.12 states an enhancement to the “preventive actions,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that the chilled water system will have a program or hardware change to bring the system chemistry parameters into compliance with EPRI TR-1007820, prior to the period of extended operation.

During the onsite audit, the staff interviewed Salem technical staff which indicated that the chilled water system was previously managed outside the Closed-Cycle Cooling Water System Program and that it would now be managed within that program. The applicant indicated that the program used to minimize corrosion and SCC and testing and inspection for these effects in this system would be changed to be consistent with EPRI guidance. The applicant also identified that system modifications would be performed to allow this system to be managed consistent with EPRI guidance. On the basis of its review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and after the enhancement is implemented, the applicant's program will be consistent with recommendations in GALL AMP XI.M21.

Enhancement 4. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that new recurring tasks would be established to enhance the performance monitoring of selected heat exchangers cooled by the component cooling system.

During the onsite audit, Salem technical staff indicated that since the chilled water system would now be managed within the Closed-Cycle Cooling Water System Program, new tasks for monitoring and inspecting the heat exchangers in this system would be added to be consistent with EPRI guidance. The staff confirmed that by being consistent with EPRI guidance, it would be consistent with the recommendations of the GALL Report. On the basis of this review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and after the enhancement is implemented, the applicant's program will be consistent with recommendations in GALL AMP XI.M21.

Enhancement 5. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that new recurring tasks will be established for enhancing the performance monitoring of selected chilled water system components.

During the onsite audit, Salem technical staff indicated that since the chilled water system would now be managed within the Closed-Cycle Cooling Water System Program, new recurring tasks would be needed to be consistent with EPRI guidance. On the basis of its review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and after the enhancement is implemented, the program will be consistent with recommendations in GALL AMP XI.M21.

Enhancement 6. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that a one-time inspection of selected components in stagnant flow areas will be established for selected chilled water system piping to confirm the effectiveness of the Closed-Cycle Cooling Water System Program. The applicant also stated these inspections will be performed prior to the period of extended operation.

The staff notes that effective water chemistry control can prevent some aging effects and minimize others. However, the water chemistry controls may not have always been adequate, and a one-time inspection can confirm the effectiveness of the program. On the basis of this review, the staff finds this enhancement acceptable because the applicant's action goes beyond the activities in the EPRI closed cooling water system guidelines, which will provide assurance that the intended function of affected components will be maintained during the period of extended operation.

Enhancement 7. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that a one-time inspection of selected Closed-Cycle Cooling Water System Program components in stagnant flow areas will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water System Program. The applicant also stated these inspections will be performed prior to the period of extended operation.

The staff notes that effective water chemistry control can prevent some aging effects and minimize others. However, locations that are isolated from the flow stream for extended periods are susceptible to gradual accumulation or concentration of agents that promote certain aging effects, and a one-time inspection can confirm the effectiveness of the water chemistry controls. On the basis of its review, the staff finds this enhancement acceptable because the applicant's action goes beyond the activities in the EPRI closed cooling water system guidelines, which will provide assurance that the intended function of affected components will be maintained during the period of extended operation.

Enhancement 8. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that a one-time inspection on the interior surfaces of selected chemical mixing tanks and associated piping will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water System Program. The applicant stated these inspections will be performed prior to the period of extended operation.

The staff notes that effective water chemistry control can prevent some aging effects and minimize others. However, locations that are isolated from the flow stream for extended periods are susceptible to gradual accumulation or concentration of agents that promote certain aging effects, and a one-time inspection can confirm the effectiveness of the water chemistry controls. On the basis of its review, the staff finds this enhancement acceptable because the applicant's action goes beyond the activities in the EPRI closed cooling water system guidelines and the performance of a one-time inspection will ensure that the system mixing tanks and associated piping are able to fulfill their intended functions throughout the period of extended operation.

Enhancement 9. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that the program will be enhanced to institute a pure water control program for the heating water and heating steam system, in accordance with EPRI TR-1007820, prior to the period of extended operation.

During the onsite audit, the staff interviewed Salem technical staff which indicated that the corrosion management of the heating water and heating steam system was transitioning to a pure water control program, which will be consistent with EPRI guidance. The staff finds this enhancement acceptable because implementation of a pure water program in accordance with EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and after the enhancement is implemented, the applicant's program will be consistent with GALL AMP XI.M21.

Enhancement 10. LRA Section B.2.1.12 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that new recurring tasks will be established for enhancing the performance monitoring of selected heating water and heating steam system components.

During the onsite audit, Salem technical staff indicated that since the heating water and heating steam system would now be managed as a pure water system within the Closed-Cycle Cooling Water System Program, new tasks for performance monitoring would be added to be consistent with EPRI guidance. On the basis of its review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines has been shown to mitigate corrosion, fouling, and microbiological growth in closed cooling water systems and after the enhancement is implemented, the program will be consistent with recommendations in GALL AMP XI.M21.

Enhancement 11. LRA Section B.2.1.12 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that a one-time inspection of selected heating water and heating steam system piping will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water System Program. The applicant also stated these inspections will be performed prior to the period of extended operation.

The staff notes that effective water chemistry control can prevent some aging effects and minimize others. However, the water chemistry controls may not have always been adequate, and a one-time inspection can confirm the effectiveness of the program. The staff finds this enhancement acceptable because the applicant’s action goes beyond the activities in the EPRI closed cooling water system guidelines and the performance of a one-time inspection of selected system piping, to confirm the effectiveness of the Closed-Cycle Cooling Water System Program for the heating water and heating steam system, will ensure that the system piping is able to fulfill its intended functions throughout the period of extended operation.

Based on its audit, the staff finds that elements one through six of the applicant’s Closed-Cycle Cooling Water System Program, with an acceptable exception and acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M21 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.12 summarizes operating experience related to the Closed-Cycle Cooling Water System Program. The applicant stated that during a self-assessment of the closed-cycle cooling water system, it identified a trend in the occurrence of out-of-specification potential of hydrogen (pH) and consequently identified the cause as the pH probe giving inconsistent readings. After replacing the probe with a different probe design, the applicant stated that there had been a significant reduction in the instances of pH being out of the control band, and for those cases, the program detected the excursions and restored the pH to the normal band. The applicant stated that this operating experience demonstrated that monitoring deficiencies are identified and corrective actions are properly implemented to maintain system functions.

In another instance, the applicant stated that as a result of numerous jacket water leaks on the diesel generators over the life of the plant, the station decided to change the corrosion control from chromates to a nitrite-based control program. The applicant also stated that several years after changing to the nitrite-based control program, technicians identified anaerobic bacteria in the jacket water of the diesel generators at levels below the limits based on EPRI guidance. The applicant stated because of this, the jacket water was changed out. The applicant stated that since this water change-out, there has not been any detection of bacteria in the diesel generator jacket water. The applicant stated that this example shows the capability of the Closed-Cycle Cooling Water System Program to identify and take corrective actions to correct parameters that are outside of their 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.12 provides the UFSAR supplement for the Closed-Cycle Cooling Water System Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2.

The staff also notes that the applicant committed (Commitment No. 12) to enhance the Closed-Cycle Cooling Water System Program prior to entering the period of extended operation. Specifically, the applicant committed to implement the following enhancements:

- The component cooling system will be enhanced to include monitoring of sulfates as part of the Closed-Cycle Cooling Water System Program

- The EDG jacket water will be monitored for azole or ammonia, chlorides, fluorides, and MIC consistent with current EPRI guidance.

- The chilled water system will have program or hardware changes to bring the system chemistry into compliance with EPRI TR-1007820, prior to the period of extended operation.

- Enhanced performance monitoring of selected heat exchangers cooled by the component cooling system will be established.

- Enhanced performance monitoring of selected components of the component cooling system will be established.

- A one-time inspection of selected components of the chilled water system piping will be established to confirm the effectiveness of the Closed-Cycle Cooling Water System Program.

- A one-time inspection of selected stagnant flow areas of the closed-cycle cooling water system will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water System Program.
- A one-time inspection of selected mixing tanks and associated piping in the closed-cycle cooling water system will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water System Program.
- The heating water and heating steam system will employ a pure water control program, in accordance with EPRI TR-1007820, prior to the period of extended operation.
- New recurring tasks will be established to ensure the performance monitoring of selected heating water and heating steam components.
- A one-time inspection of selected heating water and heating steam system piping will be completed to confirm the effectiveness of the Closed-Cycle Cooling Water System Program.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Closed-Cycle Cooling Water System 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 aging effects for which the LRA credits it. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 12 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 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.2.1.13 describes the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program as consistent, with enhancements, with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The applicant stated that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program manages loss of material for all cranes, trolley, and hoist structural components (including bolting), fuel handling systems, and applicable rails that are within the scope of license renewal. The applicant also stated that visual inspections will be used to assess the aging effects of loss of material due to corrosion and visible signs of wear and loss of preload.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M23. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M23.

The staff also reviewed the portions of the "scope of the program," "detection of aging effects," and "acceptance criteria" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.13 states that an enhancement will be made to the "scope of the program" and "parameters monitored or inspected" program elements. The applicant stated that this enhancement expands on the existing program element by adding visual inspection of structural components and structural bolts for loss of material due to general corrosion, pitting, and crevice corrosion and structural bolting for loss of preload due to self-loosening. The "scope of the program" program element of GALL AMP XI.M23 states that the program manages the effects of general corrosion on the crane and trolley structural components and the effects of wear on the rails. The "detection of aging effects" program element of GALL AMP XI.M23 states that "crane rails and structural components are visually inspected on a routine basis for degradation." The staff finds this enhancement acceptable because the enhancement related to the loss of material aging effect will make the program consistent with the recommendations in GALL AMP XI.M23 and although the loss of preload aging effect is not a specific recommendation of GALL AMP XI.M23, the aging effect can be properly managed by the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program through visual inspections and control of preload during installation and maintenance activities.

Enhancement 2. LRA Section B.2.1.13 states an enhancement to the "scope of the program" and "parameters monitored or inspected" program elements. The applicant stated that this enhancement expands on the existing program element by adding the requirement for visual inspection of the rails and the rail system for loss of material due to wear. The "scope of the program" program element of GALL AMP XI.M23 states that the program manages the effects of wear on the rails in the rail system. The "detection of aging effects" program element of GALL AMP XI.M23 states that "crane rails and structural components are visually inspected on a routine basis for degradation." The staff finds this enhancement acceptable because it will make the program consistent with the recommendations in GALL AMP XI.M23 and expands on the program elements to make them more specific.

Enhancement 3. LRA Section B.2.1.13 states an enhancement to the "acceptance criteria" program element. The applicant stated that this enhancement expands on the existing program element by requiring evaluation of significant loss of material due to corrosion for structural components and structural bolts and significant loss of material due to wear on the rails in the rail system. The "acceptance criteria" program element of GALL AMP XI.M23 states that "any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice." The staff finds this enhancement acceptable because it makes the program consistent with the recommendations in GALL AMP XI.M23.

Based on its audit, the staff finds that elements one through six of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M23 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.13 summarizes operating experience related to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The applicant stated that no occurrences of unacceptable corrosion for components within the scope of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program have been identified. The applicant also stated that since the applicant's cranes, hoists, trolleys, and fuel handling equipment have not been operated outside their design limits nor beyond their design lifetime, no fatigue-related structural failures have occurred.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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 of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.13 provides the UFSAR supplement for the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems 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 3.3-2. The staff also notes that the applicant committed (Commitment No. 13) to enhance the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program prior to entering the period of extended operation. Specifically, the applicant committed to use the existing program for license renewal and to inspect for loss of material due to wear on the rails in the rail system; loss of material due to general, pitting, and crevice corrosion on structural components and bolts; and loss of preload for structural bolting and evaluation of significant loss of material due to corrosion for structural components and structural bolts and significant loss of material due to wear on the rails in the rail system.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the 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. 13 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 Fire Protection

Summary of Technical Information in the Application. LRA Section B.2.1.15 describes the Fire Protection Program as an existing program that is consistent, with an exception and enhancements, with GALL AMP XI.M26, “Fire Protection.” The applicant stated that the program manages the effects of aging for fire barriers, the diesel fire pumps fuel oil supply lines, and the halon and carbon dioxide (CO_2) fire suppression systems and associated components through the use of periodic inspections and functional testing to detect aging effects prior to loss of intended functions. The applicant also stated that the program provides for: (1) visual inspections of fire barrier penetration seals for signs of degradation (e.g., change in material properties, loss of materials, cracking, and hardening); (2) visual examinations of fire barrier walls, ceilings, and floors in structures within the scope of license renewal at a frequency of once each refueling outage; and (3) periodic visual and functional tests to manage the aging effects of fire doors and dampers and the external surfaces of the halon and CO_2 fire suppression system components. The applicant further stated that performance tests of the diesel-driven fire pump will be used to detect degradation (corrosion) of the fuel supply lines before the loss of the component intended function occurs and to provide data for trending purposes.

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

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.M26. As discussed in the Audit Report, the staff confirmed that each element of the applicant’s program is consistent with the corresponding element of GALL AMP XI.M26, with the exception of the “detection of aging effects” and “acceptance criteria” program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

The “detection of aging effects” program element of GALL AMP XI.M26 recommends that visual inspections of the halon and CO_2 fire suppression systems be performed to detect any sign of degradation, such as corrosion, mechanical damage, or damage to dampers, and that a periodic functional test and inspection be performed at least once every 6 months. The “acceptance criteria” program element of GALL AMP XI.M26 recommends that any sign of corrosion or mechanical damage of the halon and CO_2 fire suppression systems is not acceptable. The staff noted that the applicant’s basis document for this program referenced procedures used to perform these functional tests and inspections. During its review of three procedures that are used to functionally test the relay room halon 1301 system, verify that valves in the flow path of the 10 ton CO_2 system are in their correct position, and verify the operation of the diesel area total flooding CO_2 system, the staff noted that there is no visual inspection activity to check for degradation, such as corrosion or mechanical damage. The staff also noted that the acceptance criteria identified in these procedures do not address corrosion. By letter dated June 10, 2010, the staff issued RAI B.2.1.15-2 requesting that the applicant confirm how this is considered consistent with GALL AMP XI.M26 and if it is not consistent, justify why this is not an exception or an enhancement.

In its response dated July 8, 2010, the applicant stated that the Fire Protection Program will be enhanced to include visual inspection activities to check for degradation during the performance of halon and CO_2 fire suppression system functional tests. The evaluation of this enhancement is addressed under Enhancement 3 below.

The staff also reviewed the portions of the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” 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 the exception and enhancements follows.

Exception. LRA Section B.2.1.15 states an exception to the “parameters monitored or inspected” and “detection of aging effects” program elements. The exception states that the halon and CO_2 fire suppression systems are functionally tested every refueling cycle (18 months). The “parameters monitored or inspected” and “detection of aging effects” program elements of GALL AMP XI.M26 recommend that periodic visual inspection and functional testing be performed at least once every 6 months to examine the halon and CO_2 fire suppression systems for signs of degradation.

The applicant stated that in addition to the 18-month functional testing, the halon fire suppression system is subject to visual inspection for system charge (storage tank weight) every 6 months and the low pressure CO_2 fire suppression system is subject to a weekly visual storage tank level and pressure check. The applicant also stated that these test and inspection frequencies are considered sufficient to ensure system availability and operability based on station operating history (e.g., corrective actions, completed surveillance test results) that shows that no age-related events have been found that have adversely affected system operation.

The staff reviewed the applicant’s CLB and confirmed that functional testing of the halon and CO_2 fire suppression systems is performed once every 18 months. The staff also reviewed the plant operating experience reports and did not find any evidence of age-related degradation in the halon or CO_2 systems. However, a review of the applicant’s procedures referenced in the program basis document indicates that neither the 6-month inspection for system charge nor the weekly inspection for tank level and pressure include inspection for detecting signs of degradation such as corrosion or damper damage. Therefore, it was not clear to the staff if the exception only applied to the functional test.

By letter dated June 10, 2010, the staff issued RAI B.2.1.15-1 requesting that the applicant: (1) clarify whether the exception only applies to functional testing; (2) clarify whether the Fire Protection Program performs visual inspections at least once every 6 months to examine the halon and CO_2 fire suppression systems for signs of degradation; and (3) if the visual inspection is not performed once every 6 months, justify why this is not an exception to GALL AMP XI.M26.

In its response dated July 8, 2010, the applicant stated that the recommended visual inspections for corrosion or damage are performed during these system functional tests and that this exception applies to both the functional testing and the visual inspection frequency. The applicant revised the exception to state that the halon and CO_2 fire suppression systems currently undergo functional testing and inspection every refueling cycle (18 months). The staff finds the exception acceptable because plant operating experience supports that the current inspection frequency is adequate to identify the effects of aging before loss of intended function, the applicant is performing testing in accordance with its CLBs, more frequent visual inspections for system charge (storage tank weight) are performed every 6 months, and the low-pressure CO_2 fire suppression system is subject to a weekly visual storage tank level and pressure checks.

Enhancement 1. LRA Section B.2.1.15 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. In the enhancement, the applicant stated that it will expand on the existing program elements by providing additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects, such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. The staff confirmed that the applicant included this enhancement as Commitment No. 15 in LRA Appendix A, Table A.5.

This enhancement, when implemented, will make the Fire Protection Program consistent with GALL AMP XI.M26, which recommends that visual inspection of the fire barrier walls, ceilings, and floors examines for any sign of degradation, such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Based on its review, the staff finds the enhancement acceptable because it will make the program consistent with the GALL Report.

Enhancement 2. LRA Section B.2.1.15 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements to expand on the existing program elements by providing specific guidance for examining exposed external surfaces of the fire pump diesel fuel oil supply line for corrosion during pump tests. The staff confirmed that the applicant included this enhancement as Commitment No. 15 in LRA Appendix A, Table A.5.

The staff notes that this enhancement, when implemented, will make the Fire Protection Program consistent with GALL AMP XI.M26, which recommends that performance of the fire pump be monitored during the periodic test to detect for any signs of degradation in the fuel supply lines, data for trending be provided, and acceptance criteria include that no corrosion is acceptable in the fuel supply line for the diesel-driven fire pump. Based on its review, the staff finds the enhancement acceptable because it will make the program consistent with the GALL Report.

Enhancement 3. By letter dated July 8, 2010, the applicant added an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements to expand on the existing program elements to include: (1) visual inspections of system piping and component external surfaces for signs of corrosion or other age-related degradation and for mechanical damage and (2) acceptance criteria stating that identified corrosion or mechanical damage will be evaluated, with corrective action taken as appropriate. The staff confirmed that the applicant included this enhancement in a revision to Commitment No. 15 in LRA Appendix A, Table A.5.

The staff finds this enhancement acceptable because, when implemented, it will make the Fire Protection Program consistent with GALL AMP XI.M26, which recommends that visual inspections of the halon and CO_2 fire suppression systems detect for any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers, and any signs of corrosion and mechanical damage of the halon and CO_2 fire suppression systems are not acceptable.

Based on its audit and review of the applicant's responses to RAIs B.2.1.15-1 and B.2.1.15-2, the staff finds that elements one through six of the applicant's Fire Protection Program, with acceptable exception and enhancements, are consistent with the corresponding program elements of GALL AMP XI.M26 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.15 summarizes operating experience related to the Fire Protection Program. The applicant stated two examples of deficiencies identified during routine fire door inspections where the fire door failed to close and latch properly and the deficiency was repaired and retested satisfactorily. The applicant also stated that unacceptable leakage was identified coming from fire doors that where tested in preparation for full cardox concentration testing because the seal was not in complete contact with the door and doorsill, allowing gas to escape. The applicant further stated that it inspected other fire door seals for signs of degradation and replaced and adjusted the door seals to ensure proper contact between the seal and the doorsill.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on fire protection system and components 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.1.15 provides the UFSAR supplement for the Fire Protection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 15) to enhance the Fire Protection Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) enhance the routine inspection procedures to provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates; (2) enhance the fire pump supply line functional tests to provide specific guidance for examining exposed external surfaces of the fire pump diesel fuel oil supply line for corrosion during pump tests; and (3) based on its letter dated July 8, 2010, enhance the halon and CO_2 fire suppression system functional test procedures to include visual inspection of system piping and component external surfaces for signs of corrosion or other age-related degradation and for mechanical damage and to include acceptance criteria stating that identified corrosion or mechanical damage will be evaluated, with corrective action taken as appropriate.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit, review of the applicant's Fire Protection Program, and the applicant's response to the staff's RAIs, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. The staff also reviewed the enhancements and confirmed that their implementation through Commitment No. 15 prior to the period of extended operation will make the existing AMP consistent with the GALL Report AMP to which it was compared. 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).

3.0.3.2.6 Fire Water System

Summary of Technical Information in the Application. LRA Section B.2.1.16 describes the existing Fire Water System Program as consistent, with enhancements, with GALL AMP XI.M27, "Fire Water System." The applicant stated that the program manages aging for the water-based fire protection systems through periodic inspections, monitoring, and performance testing. The applicant also stated that system functional tests, flow tests, flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. The applicant also stated that the program includes fire system main header flow tests, sprinkler system inspections, visual yard hydrant inspections, fire water storage tank inspections, fire hydrant hose inspections, hydrostatic tests, gasket inspections, volumetric inspections, fire hydrant flow tests, and pump capacity tests performed periodically to assure that the aging effect of loss of material due to corrosion, MIC, or biofouling are managed such that the system intended functions are maintained. The applicant also stated that selected portions of the fire protection system piping located aboveground and exposed to water will be inspected by non-intrusive volumetric examinations, to ensure that aging effects are managed and that wall thickness is within acceptable limits.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M27. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M27.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.16 states an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements to expand on the existing program elements to inspect selected portions of the water-based fire protection system piping located aboveground and exposed internally to fire water using non-intrusive volumetric examinations. The applicant stated that these inspections shall be performed prior to the period of extended operation and every 10 years thereafter. The staff confirmed that the applicant included this enhancement as Commitment No. 16 in LRA Appendix A, Table A.5.

GALL AMP XI.M27 recommends that wall thickness evaluations of fire protection piping be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion and that these inspections be performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. The staff finds this enhancement acceptable because performing non-intrusive examinations on the aboveground fire water piping every 10 years make the program consistent with the recommendation in GALL AMP XI.M27.

Enhancement 2. LRA Section B.2.1.16 states an enhancement to the "detection of aging effects" program element to expand on the existing program element to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5-3.1.1. The applicant stated that these inspections will be performed by the 50-year inservice date and every 10 years thereafter. The staff confirmed that the applicant included this enhancement as Commitment No. 16 in LRA Appendix A, Table A.5.

GALL AMP XI.M27 recommends that sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the period of extended operation. The staff finds this enhancement acceptable because it will make the program consistent with the recommendation in GALL AMP XI.M27.

Based on its audit, the staff finds that elements one through six of the applicant's Fire Water System Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M27 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.16 summarizes operating experience related to the Fire Water System Program. The applicant stated that in July 2003, during routine fire water system walkdowns, a small leak was found at a flow switch, which was due to a leaking gasket and seal on the switch. The applicant also stated that this flow switch was replaced and returned to service and to date, no other leaks have been found on any other flow switches on the fire water system.

The applicant stated that in February 2005, during the routine monthly fire water flow path verification, corrosion was found on the external surfaces of the fire pipe header such that paint on the 6-inch header was blistered and some of the exterior surface of the pipe could be manually removed by rubbing the surface. The applicant also stated that this degraded condition was attributed to an isolation valve packing leak located above this Section of piping and that the corrosion was only surface rust and could be easily removed. The applicant further stated that it cleaned and painted the piping and returned it to service.

The applicant stated that in February 2005, during the routine monthly fire water flow path verification walkdown, a 4-inch wet pipe sprinkler valve was found to have surface corrosion, which was determined to have originated from a packing leak from the valve that slowly corroded the valve body over time. The applicant also stated that the valve was removed and replaced with a new valve and that, based on internal operating experience review, no further corrosion or leakage has occurred at this location. The applicant further stated that the fire protection system manager has performed visual inspections of piping internal conditions when exposed during maintenance activities, and the piping internals have been observed to be in good condition with no significant internal fouling or corrosion buildup.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on fire protection system and components 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.

<u>UFSAR Supplement</u>. In LRA Section A.2.1.16, the applicant provided the UFSAR supplement for the Fire Water System Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2.

The staff notes that the applicant committed (Commitment No. 16) to enhance the Fire Water System Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) enhance the program to inspect selected portions of the water-based fire protection system piping located aboveground; these inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter; and (2) enhance the program to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5-3.1.1; these inspections will be performed prior to the 50-year inservice date and every 10 years thereafter.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Fire Water System Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 16 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared.

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).

3.0.3.2.7 Aboveground Steel Tanks

Summary of Technical Information in the Application. LRA Section B.2.1.17 describes the existing Aboveground Steel Tanks Program as consistent, with enhancements, with GALL AMP XI.M29, "Aboveground Steel Tanks." The applicant stated that the program will be applied to the fire protection water storage tank to manage the effects of exposure to the outdoor air and soil environment. The applicant also stated that this is a condition monitoring program and it credits the application of paint and coatings to the external surfaces of the in-scope tanks as a corrosion prevention measure. The applicant further stated that inspections will consist of visual inspections to determine the condition of the painted or coated external surfaces, UT thickness measurements of the bottom of the tank, and visual inspection of the grout/sealant interface for degradation. The staff noted that the applicant's inspection procedures ensure that the caulk/sealant joint between the tank and foundation interface is visually inspected during the inspection of the tank.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M29. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M29.

The staff also reviewed the portions of the "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.17 states an enhancement associated with the "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The program will be enhanced to require UT to obtain tank bottom thickness measurements. The applicant also stated that the thickness measurements will be evaluated against design thickness and corrosion allowance and significant degradation will be monitored and trended.

The staff evaluated this enhancement and finds it acceptable because UT provides direct, quantitative measurements of the tank bottom thickness and the applicant will evaluate results against design thickness requirements and corrosion allowance.

Enhancement 2. LRA Section B.2.1.17 states an enhancement to the "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The program will be enhanced to include visual inspection of the external surfaces of the fire protection water storage tank and the grout or sealant at the interface between the tank bottom and concrete foundation.

The staff evaluated this enhancement and finds it acceptable because the applicant's routine visual inspection methods address the GALL Report recommendation for periodic system walkdowns to monitor degradation of the protective paint or coating and degradation of grout or sealant, degradation of which could result in degradation of the tank's bottom.

Based on its audit, the staff finds that elements one through six of the applicant's Aboveground Steel Tanks Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M29 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.17 summarizes operating experience related to the Aboveground Steel Tanks Program. The applicant stated experience in detection of corrosion on the exterior surface of a fire protection water storage tank in which degraded paint was observed during a routine visual inspection as part of this program. The applicant also stated that corrective actions were implemented which included recoating both fire protection water storage tanks, with no further negative inspection results. The applicant described another example of operating experience in which a visual inspection of an indoor fuel oil tank revealed degraded coatings which was corrected by recoating the tank. The applicant further stated that in each case discussed above, the program effectively identified the need for corrective actions and that the corrective actions were implemented prior to significant degradation or loss of material on the underlying metal tank surfaces.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.17 provides the UFSAR supplement for the Aboveground Steel Tanks Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program, as described in SRP-LR Tables 3.3-2 and 3.4-2. The staff also notes that the applicant committed (Commitment No. 17) to enhance the Aboveground Steel Tanks Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the program to include internal UT measurements to measure the wall thickness on the bottom of the tanks and conduct routine visual inspections of the tank external surfaces and grouting or sealant at the tank bottom to foundation interface.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Aboveground Steel Tanks Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff reviewed the enhancements and confirmed that their implementation through Commitment No. 17 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Fuel Oil Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.18 describes the existing Fuel Oil Chemistry Program as consistent, with exceptions and enhancements, with GALL AMP XI.M30, "Fuel Oil Chemistry." The applicant stated that the program includes preventive activities to provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal to prevent loss of material. The applicant further stated that the fuel oil tanks within the scope of the program are maintained by monitoring and controlling fuel oil contaminants in accordance with ASTM standards. By periodically draining, cleaning, and inspecting the fuel oil tanks, the applicant stated that this provides reasonable assurance that potentially harmful contaminants are maintained at low concentrations.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the exceptions and enhancements to determine whether the AMP, with the exceptions and enhancements, is adequate to manage the aging effects for which the LRA credits it. The staff confirmed that the Fuel Oil Chemistry Program contains all the elements of the referenced GALL Report program and that the plant conditions are bounded by the conditions for which the GALL Report was evaluated.

The staff compared program elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M30. Based on its audit, the staff finds that elements one through six of the applicant's Fuel Oil Chemistry Program are consistent with the corresponding program elements of GALL AMP XI.M30 and, therefore, acceptable.

Exception 1. LRA Section B.2.1.18 states an exception to the "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The GALL Report AMP recommends periodic sampling of tanks in accordance with manual sampling standards of ASTM D 4057-95 (2000). The applicant stated that the 20,000-barrel fuel oil storage tank (S1DF-1DFE13) samples are single point samples obtained from the tank drain line located off of the bottom of the tank. This sample is not in accordance with manual sampling standards as described in ASTM D 4057. The applicant provided justification for obtaining this sample by stating that the sample results are more likely to capture contaminants, water, and sediments, thus making this a conservative sample location for fuel oil contaminants.

The staff reviewed this exception, ASTM D 4057-95, and the sampling method used by the Fuel Oil Chemistry Program. The tank bottom sampling performed by this AMP is acceptable because sampling from the tank bottom location will allow for detection of contaminants, water, and sediments, which tend to settle in the tank bottom.

The staff finds this program exception acceptable and consistent with the one described in GALL AMP XI.M30 because sampling used in the Fuel Oil Chemistry Program is equivalent or more conservative than the ASTM standard recommended by the GALL Report.

Exception 2. LRA Section B.2.1.18 states an exception to the "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The GALL Report AMP recommends periodic sampling of tanks in accordance with the manual sampling standards of ASTM D 4057-95 (2000). The applicant stated that the 350-gallon fire pump day tanks (S1DF-1DFE21 and S1DF-1DFE23) samples are single point samples obtained from the tank sight glass drain line located a few inches above the bottom of the tank. This sample is not in accordance with the manual sampling standards as described in ASTM D 4057. The applicant provided justification for obtaining this sample by stating that for fuel oil storage tanks of less than 159 cubic meters, spot sampling recommendations in ASTM D 4057 include a single sample from the middle (a distance of one-half of the depth of liquid below the liquids surface). The 350-gallon fire pump day tanks are 1.3 cubic meters, so the spot sampling recommendations in ASTM D 4057 are applicable. Although the actual sample location for the tanks is lower than prescribed by the ASTM D 4057 standard, the sample results are more likely to capture contaminants, water, and sediment, thus making this a conservative sample location for fuel oil contaminants.

The staff reviewed this exception, ASTM D 4057-95, and the sampling method used by the Fuel Oil Chemistry Program. The single point samples obtained from the tank sight glass drain line location is acceptable because sampling from the tank bottom location will allow for detection of contaminants, water, and sediments, which tend to settle in the tank bottom.

The staff finds this program exception acceptable and consistent with the one described in GALL AMP XI.M30 because sampling used in the Fuel Oil Chemistry Program is equivalent or more conservative than the ASTM standard recommended by the GALL Report.

Exception 3. LRA Section B.2.1.18 states an exception to the "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The GALL Report AMP recommends periodic sampling of tanks in accordance with the manual sampling standards of ASTM D 4057-95 (2000). The applicant stated that the 30,000-gallon diesel fuel oil storage tanks (S1DF-1DFE1, S1DF-1DFE2, S2DF-1DFE1, and S2F-1DFE2) samples consist of four samples drawn from two locations on the tank. One is from the level instrumentation block drain, which is located a few inches above the bottom of the tank. The remaining three samples are taken from the sump drain, which is located on the other side of the tank and is from the bottom of the tank. This sample is not in accordance with the manual sampling standards as described in ASTM D 4057. The applicant provided justification for obtaining the four samples by stating that for fuel oil storage tanks of less than 159 cubic meters, spot sampling recommendations in ASTM D 4057 include a single sample from the middle (a distance of one-half of the depth of liquid below the liquid's surface). The 30,000-gallon diesel fuel oil storage tanks are 113.6 cubic meters, so the spot sampling recommendations in ASTM D 4057 are applicable. Although the actual sample location for the tanks is lower than prescribed by the ASTM D 4057 standard, the sample results are more likely to capture contaminants, water, and sediment, thus making this a conservative sample location for fuel oil contaminants.

The staff reviewed this exception and ASTM D 4057-95. The four samples obtained from the tanks level instrumentation block drain and sump drain locations are acceptable because sampling from the tank bottom location will allow for detection of contaminants, water, and sediments, which tend to settle in the tank bottom.

The staff finds this program exception acceptable and consistent with the one described in GALL AMP XI.M30 because sampling used in the Fuel Oil Chemistry Program is equivalent or more conservative than the ASTM standard recommended by the GALL Report.

Exception 4. LRA Section B.2.1.8 states an exception to the "scope of the program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The GALL Report AMP recommends periodic sampling, draining, cleaning, and internal inspection of tanks to reduce the potential for loss of material by exposure to fuel oil contaminated with water and microbiological organisms. The applicant stated that multilevel sampling, tank bottom draining, cleaning, and internal inspection of the 550-gallon diesel fuel oil day tanks (S1DF-1DFE3, S1DF-1DFE4, S1DF-1DFE5, S2DF-1DF3, S2DF-1DFE4, and S2DF-1DFE5) is not periodically performed. The applicant provided justification for not performing these activities by stating that fuel oil from the 550-gallon day tanks is recirculated to the 30,000-gallon fuel oil storage tanks quarterly to prevent the accumulation of contaminants, water, and sediments. The diesel fuel oil day tanks are enclosed in the auxiliary building, which is maintained at a constant temperature. Maintaining a constant temperature reduces tank thermal cycling and reduces the potential for condensation formation within the tanks. In addition, the program will be enhanced to include a one-time inspection of each of the 550-gallon day tanks prior to the period of extended operation to confirm the absence of any significant aging effects. Should the one-time inspection reveal evidence of aging effects, the condition will be entered into the corrective action program for resolution.

The staff reviewed this exception and reviewed the performance actions recommended by the GALL Report. The recirculation of the fuel oil from the 550-gallon day tanks accompanied with the constant temperature environment is acceptable because the potential for contaminants, water, and sediment formation at the bottom of the day tanks is reduced. The performance of a one-time inspection and the entering of adverse findings into the corrective action program were found to be acceptable.

The staff finds this program exception acceptable and consistent with the one described in GALL AMP XI.M30 because: (1) the one-time inspection of the tanks will allow for detection and reporting of aging effects, and (2) the recirculation of the fuel oil to the 30,000-gallon tank, where periodic sampling for contaminants is performed, was determined to be acceptable.

Exception 5. LRA Section B.2.1.18 states an exception to the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. The GALL Report AMP recommends the addition of biocides, stabilizers, and corrosion inhibitors to prevent degradation of the fuel oil quality. The applicant stated that the program does not currently include the addition of biocides, stabilizers, or corrosion inhibitors. The applicant provided justification by stating that the program will be enhanced to require the addition of biocides, stabilizers, and inhibitors if sampling or inspection activities detect the biological breakdown of the fuel or corrosion products. The applicant also stated that the program will be enhanced to include the analysis for particulate contamination in new and stored fuel oil.

The staff reviewed this exception and the recommendations found in the GALL Report AMP. The program enhancement to require the addition of biocides, stabilizers, and inhibiters if inspection activities detect the biological breakdown of the fuel or corrosion products is acceptable.

The staff finds this program exception acceptable and consistent with the one described in GALL AMP XI.M30 because an enhancement will be made to the Fuel Oil Chemistry Program to include biocides, stabilizers, and inhibitors in response to test results that indicate biological activity and biological breakdown of the fuel or corrosion products.

Enhancement 1. LRA Section B.2.1.18 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. This enhancement provides equivalent requirements for fuel oil purity and fuel oil testing, as described by the standard TSs.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 2. LRA Section B.2.1.18 states an enhancement to the “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. This enhancement provides analysis for particulate contamination in accordance with modified ASTM 2276-00 Method A. The modification consists of using a filter with a pore size of 3 microns instead of 0.8 microns.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 3. LRA Section B.2.1.18 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “corrective actions” program elements. This enhancement requires the addition of biocides, stabilizers, and corrosion inhibitors as determined by fuel oil sampling or inspection activities.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 4. LRA Section B.2.1.18 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. This enhancement provides quarterly analysis for bacteria in new and stored fuel oil.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 5. LRA Section B.2.1.18 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. This enhancement requires visual inspection of the internal surfaces of the 350-gallon fire pump day tanks (S1DF-1DFE21 and S1DF-1DFE23) that have been drained for cleaning and sediment removal. Ultrasonic thickness examinations of the tank bottoms are also included.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 6. LRA Section B.2.1.18 states an enhancement to the "scope of the program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. This enhancement provides American Petroleum Institute gravity and flash point testing of new fuel prior to unloading.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 7. LRA Section B.2.1.18 states an enhancement to the "scope of the program," "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements. This enhancement provides visual inspection of the internal surfaces of the diesel fuel oil storage tanks (S1DF-1DFE1, S1DF-1DFE2, S2DF-2DFE1, and S2DF-2DFE2) that have been drained for cleaning and sediment removal. Ultrasonic thickness examinations of the tank bottoms are also included.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will be make the program consistent with the recommendations in GALL AMP XI.M30.

Enhancement 8. LRA Section B.2.1.18 states an enhancement to the "scope of the program," "parameters monitored or inspected," and "detection of aging effects" program elements. This enhancement verifies the absence of any significant aging effects of each of the 550-gallon diesel fuel oil day tanks by performing a one-time inspection.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will be make the program consistent with the recommendations in GALL AMP XI.M30.

Operating Experience. LRA Section B.2.1.18 summarizes operating experience related to the Fuel Oil Chemistry Program. The staff reviewed this information and interviewed the applicant's technical personnel to confirm that the applicable aging effects and industry and plant-specific operating experience have been reviewed by the applicant and are evaluated in the GALL Report. During the audit, the staff independently verified that the applicant had adequately incorporated and evaluated operating experience related to this program.

The applicant provided the following for operating experience:

(1) In 2006, a notification was written to correct the frequency of the cleaning of the 20,000 barrel main fuel oil storage tank (S1DF-1DFE13) and the diesel fuel oil storage tanks (S1DF-1DFE1, S1DF-1DFE2, S2DF-1DFE1, and S2F-1DFE2). These cleanings were previously scheduled to be done every 20 years, which was not in accordance with the industry standard of 10 years. This notification changed the frequency of the cleaning to every 10 years. Additionally, in 2008, S1DF-1DFE1 and S1DF-1DFE2 were cleaned and inspected and no significant degradation was found.

(2) In July of 2005, the analysis of the 92-day surveillance sample of the S2DF-2DFE1 indicated that the sample failed to conform to testing specifications as defined in SC.FO-LB.ZZ-0001 for 10 percent residual carbon residue. The established specification limit is less than or equal to 0.20 percent. Testing yielded a value of 0.21 percent. A review of the other tanks (S1DF-1DFE13, S1DF-1DFE2, S1DF-1DFE1, and S2DF-2DFE2) was performed and all results were satisfactory for the other tanks. The investigation of the increased value did not result in a root cause for the testing result. However, the fuel oil was determined to meet the engine manufacturer's specifications and was acceptable for use in the engines. Additionally, the review indicated that there are some variations in the test results (+/- 0.03 percent), which could account for the reading being out of specification. Subsequent tests have indicated satisfactory results.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would be ineffective in adequately managing aging effects during the period of extended operation.

The staff confirmed that the applicant addressed operating experience identified after issuance of the GALL Report. Based on its review, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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 of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.18 provides the UFSAR supplement for the Fuel Oil Chemistry Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The applicant committed to enhance the Fuel Oil Chemistry Program prior to entering the period of extended operation. Specifically, the applicant committed to the following:

(1) equivalent requirements for fuel oil purity and fuel oil testing as described by the standard TSs

(2) analysis for particulate contamination in new and stored fuel oil

(3) addition of biocides, stabilizers, and inhibitors as determined by fuel oil sampling or inspection activities

(4) quarterly analysis for bacteria in new and stored fuel oil

(5) internal inspection of the 350-gallon fire pump day tanks (S1DF-1DFE21 and S1DF-1DFE23) using visual inspections and ultrasonic thickness examination of tank bottoms

(6) sampling of new fuel oil deliveries for American Petroleum Institute gravity and flash point prior to offload

(7) internal inspection of the 30,000-gallon fuel oil storage tanks (S1DF-1DFE1, S1DF-1DFE2, S2DF-2DFE1, and S2DF-2DFE2) using visual inspections and ultrasonic thickness examinations of tank bottoms

(8) performing a one-time inspection of each of the 550-gallon diesel fuel oil day tanks to confirm the absence of any significant aging effects

The staff evaluated the commitments and finds them acceptable since it gives reasonable assurance that fuel oil quality will be adequately managed during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fuel Oil Chemistry 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 exceptions and their justifications and determines that the AMP, with exceptions, is adequate to manage the aging effects for which the LRA credits it. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Reactor Vessel Surveillance

Summary of Technical Information in the Application. In LRA Section B.2.1.19, the applicant described its Reactor Vessel Surveillance Program, stating that this existing program is consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance," with the following enhancements:

(1) state the bounding RPV inlet temperature (cold leg) limits and neutron fluence projections and provide instructions for changes ("parameters monitored or inspected" program element)

(2) describe the storage requirements and the need to retain future pulled capsules ("detection of aging effects" program element)

(3) specify a scheduled date for withdrawal of capsules including pulling one of the remaining four capsules during the period of extended operation to monitor the effects of long-term exposure to neutron embrittlement for each Salem Unit ("monitoring and trending" and "acceptance criteria" program elements)

(4) incorporate the requirements for: (1) withdrawing the remaining capsules when the monitor capsule is withdrawn during the period of extended operation and placing them in storage for reinstituting the program if required if the RPV exposure conditions

(neutron flux, spectrum, irradiation temperature, etc.) are altered and subsequently the basis for the projection to 60 years warrant the reinstitution and (2) discussing with the NRC for changes to the RPV exposure conditions and the potential need to re-institute an RPV surveillance program ("acceptance criteria" program element)

(5) require that if future plant operations exceed the limitations or bounds specified for cold leg temperatures (RPV inlet) or higher fluence projections, then the impact of plant operation changes on the extent of RPV embrittlement will be evaluated and the NRC shall be notified ("confirmation process" program element)

With these enhancements, the applicant stated that the Reactor Vessel Surveillance Program will provide reasonable assurance that loss of fracture toughness due to neutron irradiation embrittlement will be adequately managed so that the intended functions of the components within the scope of license renewal will be maintained consistent with the CLB during the period of extended operation.

Staff Evaluation. The staff reviewed the applicant's proposed Reactor Vessel Surveillance Program to confirm whether the applicant's claim of consistency with the GALL Report, with enhancements, is valid.

Appendix H of 10 CFR Part 50 specifies surveillance program criteria for 40 years of operation. GALL AMP XI.M31 specifies additional criteria for 60 years of operation. The staff determined that compliance with 10 CFR Part 50, Appendix H criteria for capsule design, location, specimens, test procedures, and reporting remains appropriate for this AMP because these items, which satisfy 10 CFR Part 50, Appendix H, will stay the same throughout the period of extended operation. To ensure that all capsules in the RPV removed and tested during the period of extended operation still meet the test procedures and reporting requirements of ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," the staff imposed the following conditions to address this specific concern:

> All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC.

The 10 CFR Part 50, Appendix H capsule withdrawal schedule during the period of extended operation is addressed according to the GALL Report's consideration of eight criteria for an acceptable RPV surveillance program for 60 years of operation.

The staff reviewed the five enhancements and the associated justifications to determine whether the Reactor Vessel Surveillance Program is adequate to manage the aging effects for which it is credited. These enhancements address four of the eight AMP acceptance criteria (Criteria 3 to 6) in GALL AMP XI.M31. Enhancement 1 is to limit the RPV cold leg temperature and neutron fluence projections. This enhancement meets the third criterion of GALL AMP XI.M31 and will increase the quality of the surveillance data. Enhancement 2 is to describe the storage requirements and the need to retain future pulled capsules. This enhancement meets the fourth criterion of GALL AMP XI.M31 and will keep used surveillance specimens for future use. Enhancement 3 is to specify capsule withdrawal schedules meeting the fifth criterion of GALL AMP XI.M31. This will provide adequate surveillance data for Salem Units 1 and 2, which have capsules with a projected neutron fluence equivalent to less than the 60-year operation for the RPV at the end of 40 years, to monitor the effects of long-term exposure to neutron irradiation.

Enhancement 4 is to incorporate the requirements for withdrawing the remaining capsules and placing them in storage when the monitor capsule is withdrawn during the period of extended operation. This enhancement meets the second part of the sixth criterion of GALL AMP XI.M31 and makes reinstituting an RPV surveillance program achievable under conditions such as change of the exposure conditions of the RPV. The first part of the sixth criterion of GALL AMP XI.M31 is for plants having capsules with a projected neutron fluence equivalent to exceeding the 60-year operation for the RPV at the end of 40 years and is, therefore, not applicable to the applicant. Enhancement 5 is to require that if future plant operations exceed the limitations or bounds specified for cold leg temperatures (RPV inlet) or higher fluence projections, then the impact of plant operation changes on the extent of RPV embrittlement will be evaluated and the NRC shall be notified. This enhancement adequately addressed the supplemental information in GALL AMP XI.M31 related to Criteria 2 and 3 (contained in the paragraph preceding “Evaluation and Technical Basis”). Therefore, all five enhancements are needed to upgrade the existing program to be consistent with GALL AMP XI.M31. The staff’s review of the Reactor Vessel Surveillance Program against the remaining three criteria is discussed below.

Criteria 1 and 2 of GALL AMP XI.M31 regard evaluation of the 60-year upper-shelf energy (USE) and pressure-temperature (P-T) limits, using RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials.” LRA Section B.2.1.19 states under “Program Description” that Salem Units 1 and 2 have documented the extent of embrittlement for USE and P-T limits for 60 years (50 effective full-power years (EFPYs)), in accordance with RG 1.99, Revision 2, using both the chemistry tables and existing surveillance data as applicable. The program description further states that surveillance capsule data from all capsules withdrawn to date was used to obtain the relationship between the mean value of nil-ductility reference temperature (RT_{NDT}) change to fluence as discussed in Position 2.1 of RG 1.99, Revision 2. Since the Reactor Vessel Surveillance Program evaluates the 60-year USE and P-T limits fully in accordance with RG 1.99, Revision 2, including the limitations specified in Criterion 2, Criteria 1 and 2 are satisfied. Criterion 7 does not apply to the Reactor Vessel Surveillance Program because it is for plants not having surveillance capsules. Criterion 8 asks for justification for not including nozzle specimens in the surveillance program. The applicant did not address this issue explicitly in LRA Section B.2.1.19. However, it was addressed indirectly in LRA Section 4.2.1, which indicated that the inlet and outlet nozzles for both Salem RPVs will experience 50-EFPY fluence less than 1E+17 neutrons per square centimeter (n/cm^2) ($E > 1.0$ MeV). Hence, neutron embrittlement of Salem RPV nozzle materials will remain low during the period of extended operation, supporting that it is unnecessary to include nozzle specimens in the Reactor Vessel Surveillance Program.

<u>Operating Experience</u>. In LRA Section B.2.1.19, the applicant cited evaluation results of three surveillance capsules withdrawn from 1992 to 2000 to conclude that the materials met the requirements for continued safe operation and the cited evaluation results provide evidence that the existing Reactor Vessel Surveillance Program will be capable of monitoring the aging effects associated with the loss of fracture toughness due to neutron irradiation embrittlement of the RPV beltline materials. The staff concurred with the applicant’s conclusion as supported by the

staff's approval of the current pressurized thermal shock (PTS) evaluation and P-T limits using information from all surveillance data in accordance with RG 1.99, Revision 2.

Based on the above evaluation of the Reactor Vessel Surveillance Program, the staff concludes that the AMP has met the eight acceptance criteria of GALL AMP XI.M31 and, therefore, the staff finds it acceptable.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Reactor Vessel Surveillance Program in LRA Section A.2.1.19. Appendix H of 10 CFR Part 50 requires licensees to submit proposed changes to their Reactor Vessel Surveillance Program withdrawal schedules to the NRC for review and approval. To ensure that this reporting requirement will carry forward through the period of extended operation, the staff has imposed a license condition to the applicant's Reactor Vessel Surveillance Program as stated earlier in the staff's evaluation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Reactor Vessel Surveillance 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 supports the requirements of the AMP. 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, with the license condition, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Buried Piping Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.22 describes the existing Buried Piping Inspection Program as consistent, with enhancements, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection." The applicant stated that buried steel piping will be managed for the aging effects of general, pitting, crevice, and microbiologically-influenced corrosion by visual inspection of excavated piping, including the associated coatings and wrappings that are installed in accordance with standard industry practices as a preventive measure. The applicant also stated that visual inspections will be conducted prior to and during the period of extended operation. The applicant further stated that there are no in-scope buried tanks.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M34. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M34. The staff noted that although elements one through six were consistent with GALL AMP XI.M34 with the inclusion of Enhancement 3, the applicant modified its program by adding Enhancements 1, 2, 4, 5, and 6 to ensure that its AMP addressed industry and plant-specific operating experience. The staff also reviewed the portions of the "preventive actions" 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.2.1.22 states an enhancement to the "preventive actions" program element. The applicant stated that it will conduct a study prior to entering the period of extended operation to assess the possibility and benefits of installing a cathodic protection system versus other mitigative and preventive actions. The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.M34 and noted that there are no recommendations in the AMP for cathodic protection systems. Therefore, this enhancement is not necessary for the staff to conclude that the program is consistent with GALL AMP XI.M34.

Enhancement 2. LRA Section B.2.1.22 states an enhancement to the "detection of aging effects" program element. The applicant stated that it will conduct a soil characterization study prior to entering the period of extended operation. The applicant also stated that the results of the study will be used to identify inspection locations with the highest risk. The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.M34 and finds this enhancement acceptable because it will result in the most risk-significant locations being identified for inspections. During the staff's review, details of this study were further enhanced, and the staff evaluation is discussed in the "operating experience" program element below.

Enhancement 3. LRA Section B.2.1.22 states an enhancement to the "detection of aging effects" program element. The applicant stated in Commitment No. 22 that:

> At least one (1) opportunistic or focused excavation and inspection will be performed on each of the Fire Protection System material groupings, which include carbon steel, ductile cast iron, and gray cast iron piping and components during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.M34 and finds this enhancement acceptable because it will result in the number of fire protection piping inspections exceeding the number recommended in GALL AMP XI.M34.

Enhancement 4. LRA Section B.2.1.22 states an enhancement to the "detection of aging effects" program element. The applicant stated in Commitment No. 22 that for buried, carbon steel, safety-related portions of the specified systems, the following inspections apply:

(a) At least one (1) opportunistic or focused excavation and inspection on each of the auxiliary feedwater and compressed air systems during the ten (10) years prior to entering the period of extended operation.

(b) At least three (3) opportunistic or focused excavations and inspections of the service water system during the ten (10) years prior to entering the period of extended operation.

(c) If, as a result of the soil characterization study, it is determined that the soil is not corrosive in the vicinity of all of the auxiliary feedwater, service water, and compressed air systems, the applicant will perform at least one (1) opportunistic or focused excavation and inspection on each of the respective systems every ten (10) years during the period of extended operation.

(d) If, as a result of the soil characterization study, it is determined that the soil is corrosive in the vicinity of the auxiliary feedwater, service water, or compressed air systems, the applicant will perform at least two (2) opportunistic or focused excavations and inspections on the respective susceptible system(s) every ten (10) years during the period of extended operation.

The applicant further stated in Commitment No. 22 that a different segment for each system will be inspected in each 10-year period.

The staff finds this enhancement acceptable and its evaluation is documented in the "operating experience" program element, below.

Enhancement 5. LRA Section B.2.1.22 states an enhancement to the "detection of aging effects" program element. The applicant stated that if the soil characterization study determines that the soil is not corrosive in the vicinity of the auxiliary feedwater, service water, and compressed air system, it will perform a second soil characterization study within approximately 15 years of the original study. The applicant also stated that the results of the second soil characterization study will be entered into the corrective action program for evaluation. The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.M34 and finds this enhancement acceptable because it will result in the most risk-significant locations being identified for inspections. Further details of this study and the staff evaluation are included in the "operating experience" program element portion of this SER under RAI B.2.1.22-03, below.

Enhancement 6. LRA Section B.2.1.22 states an enhancement to the "preventive actions" program element. The applicant stated that the buried auxiliary feedwater system piping located inside the Unit 2 fuel tube transfer area will be replaced and rerouted aboveground prior to the period of extended operation. The External Surfaces Monitoring Program will manage the aging of this piping. The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.M34 and finds this enhancement acceptable because it will result in piping being re-located to a less aggressive aging environment (i.e., air-indoor uncontrolled versus soil). It will be accessible for routine inspections. The GALL Report, item V.A-1 recommends the External Surfaces Monitoring Program for this component, material, and aging effect (i.e., loss of material due to general corrosion).

Based on its audit, the staff finds that elements one through six of the applicant's Buried Piping Inspection Program, with acceptable enhancements (Enhancement 1 was not necessary for the staff's evaluation), are consistent with the corresponding program elements of GALL AMP XI.M34 and, therefore, acceptable. The staff noted that even though the applicant has demonstrated consistency with each of the program elements in GALL AMP XI.M34, based on recent industry operating experience, the staff required further information related to the applicant's cathodic protection, coatings, and the quality of backfill in the vicinity of buried pipe. The staff issued RAIs B.2.1.22, B.2.1.22-02, and B.2.1.22-03; its evaluation is documented in the "operating experience" program element.

Operating Experience. LRA Section B.2.1.22 summarizes operating experience related to the Buried Piping Inspection Program. The applicant stated that in one example of plant-specific operating experience, wrappings were found to be missing from a portion of out-of-scope fuel oil piping. This resulted in corrosion and leakage. The piping was repaired and wrapping was installed. In another instance, a joint in the service water system failed due to loads from the road surface above. Inspections done during the piping repair excavation revealed no 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified additional operating experience which could indicate that the applicant's program may not be effective in adequately managing aging effects during the period of extended operation. By letter dated August 6, 2010, the staff issued RAI B.2.1.22 asking how the applicant will incorporate the recent industry operating experience events involving leakage from buried or underground piping into its AMRs and AMPs.

In its response dated September 7, 2010, the applicant described how during planned inspections at the Unit 1 auxiliary feedwater line, it found the pipe wall thickness was less than the nominal thickness in several areas. The applicant stated that during original construction, the coating from this line was erroneously removed. This resulted in the pipe wall thickness reduction but the pipe still met operability limits after reanalysis. The applicant also stated that as part of the extent of condition review, an area inside the Unit 1 fuel transfer tube was excavated to expose auxiliary feedwater, station air, and control air systems. Upon excavation, a small pipe leak was found on a 1-inch control air line buried in the sand. The cause of the damage was attributed to coating damage as a result of an individual stepping on the pipe. The applicant further stated that this similar configuration of piping in the Unit 2 fuel transfer tube area was also excavated as part of the extent of condition investigation and the coatings on the pipes were found to be in good condition.

The applicant stated that it has risk-ranked all buried piping in accordance with the National Association of Corrosion Engineers (NACE) and EPRI guidelines and the NEI Industry Initiative on Buried Piping uses these risk rankings to conduct inspections of the coating and external surfaces of the pipe. The applicant also stated that none of the buried piping systems have cathodic protection installed. The applicant further stated that it has committed to conduct excavated visual inspections of at least 8, when practical, linear feet of buried pipe in each material group and an additional three steel piping locations, based on its recent Unit 1 auxiliary feedwater operating experience, prior to entry into the period of extended operation and each 10-year period after entry into the period of extended operation.

Based on its review of documentation during the audit and subsequent reviews of the LRA and responses to RAIs, the staff noted that:

- all carbon steel piping is coated in accordance with appropriate industry standards
- the applicant's extent of condition review, performed as a result of discovering the missing coatings on the Unit 1 auxiliary feedwater piping, provided reasonable assurance that the missing coatings were limited to the locations identified during the corrective actions taken for the degraded condition
- the applicant will continue its extent of condition inspections by inspecting an additional 50 feet of Unit 2 auxiliary feedwater piping in the 2011 spring refueling outage

However, based on its review, the staff needed additional information to find the applicant's program acceptable. In a letter dated October 12, 2010, the staff issued a follow-up RAI B.2.1.22-02 requesting that the applicant:

(a) define what is meant by excavating 8 feet of pipe "when practical," state what alternative inspection means will be used to determine the condition of the buried pipe and its coatings, or justify why inspecting less than 8 feet is sufficient to provide reasonable assurance of the condition of the pipe and coatings

(b) justify why it is acceptable for the buried in-scope piping to not be cathodically protected

(c) clarify if any non-radioactive drain system buried pipe contains hazardous material (as defined in the GALL Report, NUREG-1801, Revision 2) and, if applicable, state what percent of in-scope buried pipe containing hazardous material will be inspected

(d) provide details on the quality of backfill in the vicinity of in-scope buried pipes

In its response dated November 10, 2010, the applicant stated that:

(a) The term "when practical" was not necessary and it has been stricken from the response.

(b) The applicant did not specifically address item (b).

(c) There are no in-scope buried portions of the non-radioactive drain system that contain hazardous material during normal operations.

(d) Bedding material within 6 inches of the pipe is required to be granular chrome ore or granular limestone. Plant procedures require that the specifications are followed when buried pipe is backfilled. Inspection procedures require documentation of materials in the backfill that do not meet specifications. Analysis of the soil removed during the 2010 inspections of the auxiliary feedwater and compressed air lines indicate that the excavated material met the specifications.

The staff finds the applicant's response to RAI B.2.1.22-02, items (a), (c), and (d) acceptable because for item (a), it has removed the "when practical" term which will result in excavations exposing 8 feet of pipe in all cases; for item (c) there are no augmented inspection recommendations for this piping, given that the in-scope buried portions of the non-radioactive drain system do not contain hazardous material; and for item (d), backfill specifications would result in no damage to coatings and recent inspections have shown that the specifications were met and no damage has occurred to coatings as a result of backfill.

However, the staff's concern, as described in RAIs B.2.1.22 and B.2.1.22-02, was not resolved for item (b) because the applicant's response did not specifically address this item. By letter dated December 20, 2010, the staff issued follow-up RAI B.2.1.22-03 requesting that the applicant provide the basis of the inspection population size and details on plant-specific data on localized soil conditions that will be used to inform sample locations.

In its response dated January 18, 2011, the applicant stated that:

> Over the last couple years, Salem has collected soil data at four separate excavation locations in the vicinity of inscope safety-related piping. The

> resistivity values for these locations ranged from approximately 13,000 - 72,000 ohm-cm with pH values ranging from 6.6 - 7.2 and only trace amounts of chlorides and sulfates, suggesting that the corrosivity of the soil is negligible. The soil composition at these locations was found to typically be sandy in nature and containing controlled backfill within six inches of the pipe, consistent with site backfill specifications and NACE SP0169-2007 guidelines.

The applicant stated that it will conduct a soil characterization study in the vicinity of each of the buried in-scope piping systems prior to the period of extended operation during which parameters such as soil composition, pH, moisture content, resistivity, sulfates, sulfides, and chlorides will be measured. The results of these samples will be compared to industry standard soil characterization metrics such as American Water Works Association (AWWA) Standard C-105 or C.P. Dillon, "Corrosion Control in the Chemical Process Industries, Materials Technology Institute of Chemical Process Industries," 1994, to determine the level of soil corrosiveness. If any soil is considered to be not corrosive, a second study will be performed within approximately 15 years. The results of this subsequent soil sample will be evaluated in accordance with its corrective action program in regard to additional inspections and informing locations of inspections. The applicant also stated that the soil characterization study will be used to inform inspection locations.

The applicant stated that of the 600 feet of buried in-scope auxiliary feedwater piping, 125 feet of Unit 1 piping located in the fuel transfer tube area was rerouted aboveground and 175 feet of buried piping was replaced. For Unit 2, the applicant committed in Commitment No. 22 to reroute 125 feet of piping located in the fuel transfer tube area to an above ground location and inspect 50 feet of the piping that will not be routed above ground. The applicant also stated that if the soil characterization study determines that the soil in the vicinity of this buried piping is not corrosive, one inspection will be performed each 10-year period starting 10 years prior to the period of extended operation, and if the soil is determined to be corrosive, one inspection will be conducted in the 10-year period prior to the period of extended operation and two inspections will be conducted in each of the 10-year periods of the period of extended operation.

The applicant stated that safety-related portions of the service water buried in-scope piping consist of 28 wall penetrations (20 are inaccessible due to building foundations and locations where excavation equipment cannot reach) and 4 connections to the circulating water system (all of which are accessible), each of which is approximately 2 feet in length. The applicant also stated that one spool was inspected during the spring 2010 refueling outage and was found to be in excellent condition. The applicant further stated that if the soil characterization study determines that the soil in the vicinity of this buried piping is not corrosive, three inspections will be performed in the 10 years prior to the period of extended operation and one inspection during each 10-year period of the period of extended operation, and, if the soil is determined to be corrosive, three inspections will be conducted in the 10-year period prior to the period of extended operation and two inspections will be conducted in each of the 10-year periods of the period of extended operation.

Alternative actions will be taken, such as broadband electromagnetic methods, to assess the condition of the inaccessible portions of the piping from external inspection safety-related service water spools. The applicant also stated that deficiencies identified during these inspections would be entered into the corrective action program and, if appropriate, ultrasonic thickness measurements would be obtained to ensure that the pipe wall meets minimum design thickness requirements.

Approximately 550 feet of the nonsafety-related portion of the Unit 1 service water system buried in-scope piping was examined using pulsed eddy current methods, and the inspection did not identify any indications of degradation in the piping. The applicant also stated that it will conduct similar testing on the 1,050 feet of buried in-scope service water piping on Unit 2 during the spring 2011 outage.

Of the 1,700 feet of buried, safety related, in-scope compressed air piping, 175 feet of Unit 1 piping was inspected during the spring 2010 outage, and 60 feet was inspected in 2009. The piping was found to be in good condition, with one exception of a degraded location discussed in the September 7, 2010, RAI response. Fifty feet will be inspected during the spring 2011 outage. The applicant also stated that if the soil characterization study determines that the soil in the vicinity of this buried piping is not corrosive, one inspection will be performed each 10-year period starting 10 years prior to the period of extended operation, and, if the soil is determined to be corrosive, one inspection will be conducted in the 10-year period prior to the period of extended operation and two inspections will be conducted in each of the 10-year periods of the period of extended operation.

The staff finds the applicant's proposal and response to RAIs B.2.1.22, B.2.1.22-02, and B.2.1.22-03 acceptable because:

- Although the plant-specific operating experience includes two leaks, the coating failures that led to the leaks were not age-related. One resulted from an installation error when the joint was wrapped and the other was due to an individual stepping on the pipe. In addition, the applicant has found no evidence of coating degradation during a significant number of excavated pipe inspections.

- The applicant is using standard industry documents such as EPRI 1016456, "Recommendations for an Effective Program to Control the Degradation of Buried Pipe," and the NEI Industry Initiative on Buried Piping to conduct risk rankings, thus ensuring that the most risk-significant locations will be inspected.

- The applicant has appropriate backfill specifications. Recent inspections have demonstrated that the backfill meets the specification requirements, and there has been no damage to coatings from the backfill.

- Preventive measures are in accordance with standard industry practices for maintaining external coatings and wrappings.

- No buried in-scope piping contains hazardous materials.

- The applicant has committed to perform a soil characterization study in the vicinity of each buried pipe system and if the soil is determined to be corrosive, the applicant will use the results to double the number of inspections and to identify the highest risk ranked locations for excavated inspections. The applicant will use standard corrosion parameter ranking methodologies such as AWWA C-105 or C.P. Dillon, "Corrosion Control in the Chemical Process Industries, Materials Technology Institute of Chemical Process Industries," 1994, to determine the level of soil corrosiveness. In addition, the applicant has committed (Commitment No. 22) to repeat the soil characterization study in approximately 15 years for any locations that were initially determined to be noncorrosive.

- As a result of its extent of condition reviews of the missing coatings on the Unit 1 auxiliary feedwater piping, the applicant has conducted a significant number of inspections of the auxiliary feedwater and compressed air system piping in the 10 years prior to the period of extended operation. A total of 225 feet of auxiliary feedwater piping either has been inspected or will be inspected (Commitment No. 22) equivalent to 22 inspections. A total of 235 feet of compressed air piping has been inspected, equivalent to 23 inspections. In addition, the applicant has committed to inspect 3 of the 12 accessible 2-foot segments of safety-related service water piping spools prior to the period of extended operation, one of which has been completed with satisfactory results.

- Approximately 550 feet of the 1,640 feet of the nonsafety-related portion of the service water system buried in-scope piping was examined using pulsed eddy current methods, and the inspection did not identify any indications of degradation in the piping.

- The applicant will conduct six inspections, inclusive of the fire protection (3), service water (1), auxiliary feedwater (1), and compressed air systems (1), during each of the 10-year inspection periods within the period of extended operation. The applicant will conduct up to nine inspections during each of these 10-year inspection periods if the soil characterization study demonstrates that the soil is corrosive (i.e., the service water, auxiliary feedwater, and compressed air system inspections will be doubled for any system where the soil is determined to be corrosive).

- The Unit 1 auxiliary feedwater piping still met operability limits despite over 30 years of operation with no coatings on a significant portion of the piping and no cathodic protection.

The staff also noted that the extensive inspections conducted or being conducted in the 10-year period prior to the period of extended operation and those that will be conducted during the period of extended operation establish a reasonable basis for the staff to conclude that the CLB function(s) of the buried in-scope systems will be maintained. The staff's concerns described in RAIs B.2.1.22, B.2.1.22-02, and B.2.1.22-03 are resolved. Open item OI 3.0.3.2.10-1 is closed.

Based on its audit, review of the application, and review of the applicant's responses to RAIs B.2.1.22, B.2.1.22-02, and B.2.1.22-03, the staff finds that the operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.22 provides the UFSAR supplement for the Buried Piping Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2.

The staff also notes that the applicant committed (Commitment No. 22) to enhance the Buried Piping Inspection Program prior to entering the period of extended operation. Specifically, the applicant committed to: (a) conduct a study prior to entering the period of extended operation to assess the possibility and benefits of installing a cathodic protection system versus other mitigative and preventive actions; (b) conduct a soil characterization study prior to entering the period of extended operation; (c) conduct focused or opportunistic excavations and inspections on each of the fire protection system material types including steel, ductile cast iron, and gray cast iron buried in-scope piping during each 10-year period starting 10 years prior to the period of extended operation; (d) conduct at least one focused or opportunistic excavation and inspection on each of the auxiliary feedwater and compressed air systems, and three on the service water system in the 10-year period prior to entering the period of extended operation, if the soil characterization study results determine that the soil is not corrosive in the vicinity of all of the auxiliary feedwater, service water, and compressed air systems; (e) perform at least one opportunistic or focused excavation and inspection on each of the systems every 10-year period during the period of extended operation if the soil characterization study results determine that the soil is not corrosive in the vicinity of all of the auxiliary feedwater, service water, or compressed air system, or perform at least two opportunistic or focused excavation and inspections on each of the susceptible systems every 10-year period during the period of extended operation; (f) perform a second soil characterization study within approximately 15 years of the original study if the results of the soil characterization study indicate that soil is not corrosive in the vicinity of the auxiliary feedwater, service water, and compressed air system; and (g) replace and reroute aboveground the buried auxiliary feedwater system piping located inside the Unit 2 fuel tube transfer area prior to the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Buried Piping Inspection 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 the applicant's implementation of these enhancements through Commitment No. 22 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B.2.1.23 describes the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as consistent, with an exception, with GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping." The applicant stated that the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is a new program that: (1) will be implemented prior to the period of extended operation and within the last 10 years of the current operating period; and (2) manages the aging effect of cracking in stainless steel ASME Code Class 1 piping, piping elements, and piping components less than 4 inches nominal pipe size (NPS) and greater than or equal to 1 NPS (Table IWB-2500-1, Examination Category B-J, Item No. B9.21) in reactor coolant and treated water environments. The applicant further stated that there has not been cracking of ASME Code Class 1 small-bore piping at its site and should evidence of aging be revealed by the one-time inspection, periodic inspection will be proposed.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M35. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M35, with the exception of the "parameters monitored or inspected" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

The "parameters monitored or inspected" program element of GALL AMP XI.M35 recommends that inspections will detect cracking in ASME Code Class 1 small-bore piping. LRA Sections B.2.1.23 and A.2.1.23 state that socket welds that fall within the weld examination sample will be examined using VT-2. The staff noted that a visual inspection of the outside diameter will not detect cracking initiated from the inside of the socket weld before leakage occurs. By letter dated June 11, 2010, the staff issued RAI B.2.1.23-1 requesting that the applicant justify how VT-2 will detect cracking that initiates from the inside of the socket weld before leakage occurs.

In its response dated July 8, 2010, the applicant stated that as industry technology advances and methods become available to detect and characterize flaws in small-bore socket welds, in addition to the VT-2 visual examinations, Salem Units 1 and 2 will perform four volumetric examinations, two per unit, from a population of 36 susceptible Class 1 small-bore socket welds on Unit 1 and 34 susceptible Class 1 small-bore socket welds on Unit 2. The applicant further stated that the locations for the volumetric socket weld examinations will be determined by selecting the socket welds where the highest likelihood of small-bore socket weld degradation could exist.

Based on its review, the staff finds the applicant's response to RAI B.2.1.23-1 acceptable because the applicant has committed to volumetric examination of small-bore piping socket welds which is capable of detecting cracking initiated from the inside wetted area of the weld. The staff's concern described in RAI B.2.1.23-1 is resolved.

The staff also reviewed the portions of the "scope of the program" 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.

Exception. LRA Section B.2.1.23 states an exception to the "scope of the program" program element. Specifically, the exception states that GALL AMP XI.M35 references the interim guidance contained in EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," while the applicant uses a more recent revision to the MRP issue regarding thermal fatigue. The applicant also stated that since the publication of the GALL Report, the interim guidance contained in EPRI Report 1000701 has been supplemented by a more complete set of guidelines on thermal fatigue issues for lines connecting to the RCS. Furthermore, the applicant used these more recent guidelines contained in EPRI Report 1011955, "Materials Reliability Program Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)."

The staff noted that MRP-24 was an interim guidance that was issued in January 2001 and MRP-146 was issued in June 2005. The staff further noted that MRP-146 expanded on MRP-24 to provide recommendations for an ongoing fatigue management program in affected lines. The staff noted that following the issuance of MRP-24, additional testing and evaluations were undertaken by industry to better understand the thermal fatigue mechanisms that had been responsible for cracking in the non-isolable, normally-stagnant branch lines. The staff reviewed MRP-146 and noted that this guideline is a replacement for MRP-24 that is based on more recent testing and analytical modeling and provides a more comprehensive approach to assure that thermal fatigue cracking will not occur. The staff also noted that MRP-146 includes: (1) a larger scope of RCS-attached piping; (2) a more detailed screening and analytical evaluation approach; (3) an evaluation of the adequacy of monitoring systems, where monitoring is used to show that valve in-leakage is not a factor; and (4) inspection guidelines, with inspection intervals for all lines where assessment indicates the potential for thermal fatigue when compared to MRP-24. The staff also noted that draft NUREG-1801, Revision 2 (ADAMS Accession No. ML101320104), dated April 2010, has proposed the use of MRP-146.

Based on its review, the staff finds this exception acceptable because the applicant is using the guidance from MRP-146 which provides more detailed and conservative guidance when compared to MRP-24, which is recommend by the GALL Report.

Based on its audit and review of the applicant's response to RAI B.2.1.23-1, the staff finds that elements one through six of the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program, with an acceptable exception, are consistent with the corresponding program elements of GALL AMP XI.M35 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.23 summarizes operating experience related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The applicant stated that it has not experienced cracking of ASME Code Class 1 small-bore piping resulting from SCC or thermal and mechanical loading. The applicant provided results of inspections that demonstrate objective evidence that the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is capable of both monitoring and detecting the aging effects of cracking and, therefore, there is sufficient confidence that the implementation of the program will provide additional assurance that either aging of small-bore ASME Code Class 1 piping is not occurring or the aging is insignificant.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.1.23 provides the UFSAR supplement for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2.

The staff also notes that the applicant committed (Commitment No. 23) to implement the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Piping 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 aging effects for which the LRA credits it. 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).

3.0.3.2.12 Lubricating Oil Analysis

Summary of Technical Information in the Application. LRA Section B.2.1.27 describes the existing Lubricating Oil Analysis Program as consistent, with an exception, with GALL AMP XI.M39, "Lubricating Oil Analysis." The applicant stated that the program provides oil condition monitoring activities to manage loss of material and reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. The applicant uses sampling, analysis, and condition monitoring activities to identify specific wear products, contamination, and physical properties of lubricating oil within operating machinery.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The staff reviewed the exception to determine whether the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. The staff confirmed that the Lubricating Oil Analysis program contains all the elements of the referenced GALL Report program and that the plant conditions are bounded by the conditions for which the GALL Report was evaluated.

In comparing program elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M39, the staff noted that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M39.

Exception. LRA Section B.2.1.27 states an exception to the "parameters monitored or inspection" program element. The GALL Report AMP recommends the determination of flash point. The applicant stated that the determination of flash point in lubricating oil is used to indicate the presence of highly volatile or flammable materials in a relatively nonvolatile or nonflammable material, such as found with fuel contamination in lubricating oil. The applicant stated that flash point is measured for new lubricating oil, but is not measured for inservice lubricating oil components within the scope of the program except for inservice EDG lubricating oil. The applicant provided justification for not performing flash point on inservice lubricating oil for components within the scope of the program by stating that the EDG inservice lubricating oil is the only potential application for the introduction of highly volatile or flammable materials (e.g., diesel fuel into the lubricating oil).

The staff reviewed this exception and the recommendations found in the GALL Report AMP. The determination of flash point for the EDG lubricating oil and new lubricating oil was found to be acceptable since the EDG lubricating oil was found to be the only potential application for the introduction of highly volatile or flammable materials.

The staff finds this program exception acceptable and the program consistent with the one described in GALL AMP XI.M39 because the applicant has stated that flash point determinations are being conducted on those systems that have the potential for the introduction of highly volatile or flammable materials.

Operating Experience. LRA Section B.2.1.27 summarizes operating experience related to the Lubricating Oil Analysis Program. The staff reviewed this information and interviewed the applicant's technical personnel to confirm that the applicable aging effects and industry and plant-specific operating experience have been reviewed by the applicant and are evaluated in the GALL Report. During the audit, the staff independently verified that the applicant had adequately incorporated and evaluated operating experience related to this program.

The applicant provided the following for operational experience:

(1) In April 2004, a lubricating oil sample was taken from the Salem Unit 3 gas turbine in accordance with the predictive maintenance program. The analysis indicated moisture content and total acid number (TAN) Alert Levels. It was recognized that the conditions could result in bearing damage. The condition was entered into the corrective action program. Prompt actions were initiated to change the lubricating oil and filter. These actions were completed in June 2004. Data since June 2004 shows moisture content and TAN returned to their normal ranges.

(2) In January 2004, a lubricating oil sample was taken from the lower bearing assembly of a circulating water pump motor in accordance with the predictive maintenance program. The analysis indicated an increase in wear metal particles and a higher than normal TAN. The levels of the wear metals iron, copper, and lead did not indicate a bearing problem. The condition was entered into the corrective action program. The vibration data was reviewed and it also did not indicate a bearing problem. The elevated TAN was an indication of possible increased oxidation of the oil. The sample results were verified and discussed with system engineering. Although there was no indication of a significant problem with the lubricating oil, the recommendation was made to replace the lubricating oil at the next available window as a prudent action to protect the bearing. Prior to this replacement, additional sampling and analysis was performed in March 2004 and June 2004 to monitor the condition of the lubricating oil and to ensure that the results of the January 2004 sample were accurate.

    These two additional samples indicated acceptable wear metal particle counts and TAN numbers. The sample from January 2004 was deemed to have been taken using a bad sampling technique. This apparent bad sampling technique was discussed with the personnel performing sampling. Replacement of the lubricating oil was canceled. Therefore, this example provides objective evidence that the Lubricating Oil Analysis Program is capable of making prudent recommendations based on sample results, performing additional sampling to monitor critical lubricating oil parameters, and to verify the validity of earlier samples, and adjusting corrective actions based on all of the analytical information.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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.

The staff confirmed that the applicant addressed operating experience identified after issuance of the GALL Report. Based on its review, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of this program has resulted in the applicant taking appropriate corrective actions. Therefore, 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.2.1.27 provides the UFSAR supplement for the Lubricating Oil Analysis Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Lubricating Oil Analysis 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 aging effects for which the LRA credits it. 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).

3.0.3.2.13 ASME Section XI, Subsection IWE

Summary of Technical Information in the Application. LRA Section B.2.1.28 describes the existing ASME Section XI, Subsection IWE Program as consistent, with enhancements, with GALL AMP XI.S1, "ASME Section XI, Subsection IWE." The applicant stated that the ASME Section XI, Subsection IWE Program is a condition monitoring program that provides for inspection of the containment liner plate including its integral attachments, penetration sleeves, pressure-retaining bolting, personnel airlock and equipment hatches, moisture barrier, and other pressure-retaining components. The applicant also stated that the scope of the ASME Section XI, Subsection IWE Program is consistent with the scope identified in ASME Code Section XI, Subsection IWE-1000 and includes the containment moisture barrier.

The applicant included two enhancements to the ASME Section XI, Subsection IWE Program to address: (1) inspection of the inaccessible liner plate covered by insulation and lagging and

(2) visual examination of 100 percent of the moisture barrier to the extent practical within the limitation of design, geometry, and materials of construction of the components.

In a response to RAI B.2.1.28-2, in a letter dated June 30, 2010, the applicant clarified the commitment in Enhancement 1. The applicant stated that Enhancement 1 will include inspection of a random sample of containment liner surfaces behind the containment liner insulation prior to the period of extended operation. The sampling plan is based on guidance in EPRI TR-107514, "Age Related Degradation Inspection Method and Demonstration: in Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application." The applicant further stated that the population size of containment liner insulation panels in each Unit is about 264 panels, so a sample size of 57 will meet the statistical confidence level of at least 95 percent that 95 percent of the containment liner plate behind the containment liner insulation meets the ASME Code Section XI, Subsection IWE-3500 acceptance criteria.

The second program enhancement will involve trimming the bottom edge of the stainless steel insulation lagging, if necessary, to provide access for inspection of the moisture barriers. The applicant provided details of corrective actions required for implementing Enhancement 2 in its response to RAI B.2.1.28-1, in a letter dated June 30, 2010. These corrective actions were identified as a follow-up to the inspection performed in 2009 and 2010.

The applicant also stated in the LRA that the program complies with ASME Code Section XI, Subsection IWE requirements for metallic shell and penetration liners of Class CC pressure-retaining components and their integral attachments in ASME Code Section XI, 1998 Edition including 1998 Addenda in accordance with the provisions of 10 CFR 50.55a.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S1. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.S1.

The staff also reviewed the portions of the "scope of the program" 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.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves inspection of a sample of the inaccessible liner plate covered by insulation and lagging prior to the period of extended operation and every 10 years thereafter. The applicant further stated that if unacceptable degradation is found, additional insulation will be removed as necessary to determine the extent of the condition in accordance with the corrective action program. In response to RAI B.2.1.28-2, the applicant stated that prior to the period of extended operation, 57 containment liner insulation panels per Unit will be selected for examination. The examinations will be conducted by either: (1) removing the containment liner insulation panels and performing a visual inspection or (2) using a pulsed eddy current (PEC) remote inspection, with the containment liner insulation left in place, to detect evidence of loss of material. If evidence of loss of material is detected using PEC, the containment liner insulation panel will be subsequently removed to allow for visual and UT examination.

Enhancement 1 also has Commitment No. 28 to remove one containment liner insulation panel selected at random, from each quadrant, in each of the three inspection periods of the 10-year inspection interval during the period of extended operation. Therefore, a total of 12 containment liner insulation panels will be selected in each unit, during each 10-year inspection interval, to allow for examination of the containment liner behind the containment liner insulation. The applicant further stated that randomly selected containment liner insulation panels in each quadrant will not include containment liner insulation panels previously selected.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1. The staff noted that inspection of the inaccessible liner plate covered by insulation is required to ensure that liner plate degradation found adjacent to the moisture barrier at the concrete floor and liner plate interface does not extend to the liner plate located behind the insulation. The selection of 57 insulation panels, out of a total of 264, for visual or PEC inspection of the liner plate will provide a statistical confidence level of 95 percent that 95 percent of the inaccessible portion of the liner plate meets the acceptance standards of ASME Code Section XI, Subsection IWE-3500. The staff also noted that if the acceptance criteria defined in IWE-3500 is not satisfied, the sample size will be modified as recommended by EPRI TR-107514.

The staff is concerned about the use of PEC to identify degradation of inaccessible portions of the liner plate behind the insulation because it has not been used in a similar situation in the past and is not recommended by ASME Code Section XI, Subsection IWE. The applicant in a conference call, dated June 30, 2010, stated that the use of the PEC remote inspection method, with the containment liner insulation left in place, to detect evidence of loss of material is being reviewed. The applicant further stated that it will require proof that the PEC is an effective inspection method for detecting degradation of the liner before it is used for Salem IWE examination. Calibrated standards will be used and the ASME authorized nuclear inservice inspector (ANII) will witness the mock-ups. If the PEC method is not effective, then the panels will be removed to provide access for visual inspection. The staff considers this approach for the use of PEC acceptable because the PEC method's effectiveness will be first tested and documented in mock-ups before it is used to identify containment liner plate degradation.

Based on its review, the staff concludes that the actions proposed by the applicant for Enhancement 1 are consistent with the corresponding program element in GALL AMP XI.S1.

Enhancement 2. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves visual inspection of 100 percent of the moisture barrier located at the junction between the containment concrete floor and the containment liner. The applicant stated that the inspections will be performed in accordance with the ASME Section XI, Subsection IWE Program requirements to the extent practical within the limitation of design, geometry, and materials of construction of the components. In order to perform the moisture barrier inspections, the applicant stated that it may be necessary to trim the bottom edge of the stainless steel insulation lagging. The applicant further stated that if unacceptable degradation is found, corrective actions, including extent of the condition, will be addressed in accordance with the corrective action program.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1. The staff noted that the applicant considered it prudent to make the moisture barrier behind the liner plate insulation accessible for visual examination prior to the period of extended operation to resolve concerns involving corrosion in this area. The 100 percent visual examination of the moisture barrier, if accessible, is required during each inspection period in accordance with ASME Code Section XI, IWE Table 2500-1. The staff further noted that additional insulation and lagging will be removed to provide access for determining the extent of the condition if degradation is found. Therefore, the staff concludes that the actions proposed by the applicant for Enhancement 2 are consistent with the corresponding program element in GALL AMP XI.S1.

Based on its audit, the staff finds that elements one through six of the applicant's ASME Section XI, Subsection IWE Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.S1 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.28 summarizes operating experience related to the ASME Section XI, Subsection IWE Program. The applicant described four examples of operating experience for the Salem concrete containment liner and its integral attachments, penetration sleeves, pressure-retaining bolting, personnel airlock and equipment hatches, moisture barrier, and other pressure-retaining components. This description includes ISI findings performed in accordance with the applicant's ASME Section XI, Subsection IWE Program.

The applicant stated that corrosion products were identified below the Salem Unit 1 containment liner insulation in 1995. In order to allow examination of the inaccessible liner, the applicant removed the insulation panel, performed a visual examination, and found the liner to be acceptable. In addition, the applicant performed UT inspections which revealed that all thickness readings were greater than the nominal wall thickness. The applicant further stated that the source of the corrosion product debris was not identified.

In 2005, the applicant noted that borated water was leaking down the inside of the Unit 2 containment wall. The applicant removed the liner insulation, inspected the area, and reported that no visible degradation was noted on the containment liner. To confirm visual inspection results, the applicant performed UT measurements of the containment liner and reported that all thickness readings were greater than the nominal wall thickness.

Another incident occurred in 2007, when the applicant found borated water leaking near the Unit 1 containment sump. An examination was performed but the applicant found no corrosion of the containment liner or degradation of the moisture barrier. To address the situation, the applicant began monthly monitoring activities to inspect and clean the boric acid leakage from around the containment sump enclosure until the sump leakage issue was resolved.

During the Unit 1 refueling outage in 2008, the applicant conducted a sampling inspection of the normally inaccessible containment liner and moisture barrier located behind the insulation panels. The applicant exposed these areas for inspection due to industry experience as noted in NRC IN 2004-09 and experience at Robinson and Indian Point which have a similar insulated liner configuration. Four stainless steel panels and the associated insulation (one in each quadrant) were removed just above the floor elevation and inspected by the applicant. The applicant reported that the moisture barrier and the liner condition were found acceptable in all areas inspected and indicated that a similar inspection is planned for the Unit 2 containment liner.

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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified operating experience which could indicate that the applicant's program may not be effective in adequately managing aging effects during the period of extended operation. The staff determined the need for additional clarification, which resulted in the issuance of two RAIs.

In LRA Section B.2.1.28, the applicant discussed actions that were taken to address age-related degradation issues found between 1995 and 2008 at its Salem Units 1 and 2 concrete containment structures. These issues are also discussed in the operating experience program element for the ASME Section XI, Subsection IWE Program. According to the applicant, operating experience related to NRC INs 86-99, 88-82, and 89-79 that describe occurrences of corrosion in steel containment shells; liner plate corrosion issues described in NRC IN 97-10; and topics in NRC IN 2004-09 was addressed. However, the operating experience program element for the applicant's ASME Section XI, Subsection IWE Program does not discuss operating experience related to liner plate corrosion. In addition, the applicant reported that corrosion products were identified in 1995 below the Salem Unit 1 containment liner insulation, but the source of the corrosion products was not identified. The applicant also identified an action plan for addressing liner wall corrosion that was found at Salem Unit 2 during the 2R17 refueling outage. The applicant evaluated containment liner and pressure test channel corrosion and concluded that, "The liner wall corrosion has reduced the wall thickness below the design nominal; however, the thickness is above the minimum and will not corrode below minimum wall during the next refueling outage when the region will be coated." This evaluation included an action plan that involved conducting a root cause investigation and developing and implementing long-term recommended repairs at the next refueling outage.

By letter dated April 15, 2010, the staff issued RAI B.2.1.28-1 requesting that the applicant: (1) provide details of borated water leakage, if any, observed inside the Unit 2 containment during the 2009 refueling outage; (2) explain why augmented inspections of the liner plate and the moisture barrier were not performed in successive inspection intervals as required by IWE-1242 since 1995; (3) provide a summary of the liner plate degradation, including loss of liner plate thickness due to corrosion, integrity of leak chase channels, and condition of moisture barriers, as observed during the most recent inspections of Unit 1 and 2 containments; and (4) provide detailed future plans for determining corrective actions, including commitments and completion schedules for addressing steel liner plate corrosion and moisture barrier deterioration in Unit 1 and 2 containments.

In its response to RAI B.2.1.28-1, issue (1), dated May 13, 2010, the applicant stated that during the most recent Salem Unit 1 outage in the spring of 2010, no active leakage from the reactor cavity and fuel transfer canal telltales was observed. The applicant further stated that during the most recent Salem Unit 2 outage in the fall of 2009, a 60 drip per minute leak of borated water was observed at the fuel transfer canal telltale, above the door to the letdown heat exchanger room. Borated water was observed on the containment liner plate moisture barrier under the fuel transfer canal. These leaks were attributed to reactor cavity leakage. The containment liner plate and moisture barrier were examined and found to meet the IWE acceptance criteria.

The applicant responded to RAI B.2.1.28-1, issue (2) by stating that prior to April 2000, inspection of the containment was performed under the Structures Monitoring Program in accordance with 10 CFR 50.65 and 10 CFR Part 50, Appendix J. Augmented examination requirements of IWE-1242 did not apply. The applicant further stated that Salem began implementation of containment inservice inspection (CISI) in accordance with ASME Code Section XI, Subsection IWE as mandated by 10 CFR Part 50.55a in April 2000. Since that time, 100 percent of accessible surface areas of the Salem Unit 2 containment liner plate were examined each inspection period of the first CISI interval in accordance with IWE-3500. The ASME Section XI, Subsection IWE Program and examinations identified no surface areas of the containment liner plate that require augmented examinations as specified in IWE-1242. The 2009 containment liner plate examinations identified areas that require augmented examination. These augmented examination areas have been identified for inclusion in the Salem plan for the second CISI interval, which started in April 2010.

The applicant responded to RAI B.2.1.28-1, issue (3) by stating that some local corrosion was observed in the ¾-inch thick knuckle plate liner area above the floor for both units, but all readings met acceptance criteria for loss of material less than 10 percent of the thickness in the analysis. The minimum thicknesses measured were 0.721 inch and 0.677 inch for Units 1 and 2, respectively.

The applicant also stated that four containment liner plate insulation panels were removed at each Unit to permit examination of the exposed ½-inch thick liner plate. Corrosion of the exposed liner plate was observed, but all thickness readings met acceptance criteria for loss of material less than 10 percent of the thickness. The minimum thicknesses measured were 0.452 inch and 0.518 inch for Units 1 and 2, respectively. The applicant also stated that all of the accessible vertical leak chase channels for both units were examined. One channel for Unit 1 and six channels for Unit 2 had corrosion that extended through the channel wall (hole). The leak chase channels with the holes were cleaned out to the extent possible, and the channel and containment liner plate were visually examined with a boroscope beneath the containment floor. The channels with the holes were cut at the floor and capped to prevent moisture intrusion.

The applicant further stated that 100 percent of the moisture barrier area at the containment liner plate to concrete floor interface for both units was inspected and repaired or replaced where it did not meet the IWE acceptance criteria. For Unit 2, the applicant stated that a short segment of the moisture barrier was removed in an area with significant corrosion of the ¾-inch thick knuckle plate above the moisture barrier, where the corrosion was suspected to occur below the moisture barrier. The moisture barrier was removed to a depth of approximately 1 inch. Some corrosion of the ¾-inch thick knuckle plate was noted below the surface of the moisture barrier at the floor level, but the corrosion of the ¾-inch thick knuckle plate did not extend below the portion of the moisture barrier that was removed. The ¾-inch thick knuckle plate met the IWE acceptance criteria.

The applicant responded to RAI B.2.1.28-1, issue (4) by stating that degradation was found as a result of implementation of Enhancement 2 to its ASME Section XI, Subsection IWE Program. As a result, areas that were previously inaccessible for inspection were examined and evaluations verified the adequacy of existing conditions as described above for issue (3).

According to the applicant, the following corrective actions were completed and additional corrective actions were specified:

Unit 1 - corrective actions completed during the refueling outage in the spring of 2010:

- Examination of 100 percent of the accessible ½-inch containment liner plate and moisture barrier.
- UT measurements of the ¾-inch containment liner (knuckle plate) around the perimeter of the containment.
- UT measurements of the ½-inch containment liner plate where insulation panels were removed and loss of material was observed.
- Coating repairs of the ¾-inch containment liner (knuckle plate).
- The one vertical leak chase channel with a hole was capped.
- Coating repairs at areas where containment liner insulation panels were removed to allow for containment liner plate inspection and corrosion was observed.
- The moisture barrier was repaired or replaced.
- Evaluation to confirm the identified loss of material is acceptable.

Unit 1 - additional corrective actions to be completed prior to the period of extended operation:

- Perform augmented examinations of the ¾-inch containment liner (knuckle plate) at 78-foot elevation in accordance with IWE-2420.
- Perform augmented examinations of the ½-inch containment liner plate behind insulation panels, where loss of material was previously identified, in accordance with IWE-2420.
- Remove ½-inch containment liner insulation panels, adjacent to accessible areas where there are indications of corrosion, to determine the extent of condition of the existing corroded areas of the containment liner plate.

Unit 2 - corrective actions completed during the refueling outage in the fall of 2009:

- Examination of 100 percent of the accessible ½-inch containment liner plate and moisture barrier.
- UT measurements of the ¾-inch containment liner (knuckle plate) around the perimeter of the containment.
- UT measurements of the ½-inch containment liner plate where insulation panels were removed and loss of material was observed.
- The six vertical leak chase channels with a hole were capped.
- Evaluation to confirm the identified loss of material is acceptable.

Unit 2 - additional corrective actions to be completed prior to the period of extended operation:

- Examine the accessible ¾-inch containment liner (knuckle plate). If corrosion is observed to extend below the surface of the moisture barrier, excavate the moisture barrier to sound metal below the floor level and perform examinations as required by IWE.

- Perform remote visual inspections, of the six capped vertical leak chase channels, below the containment floor to determine extent of condition.

- Remove the concrete floor and expose the ¼-inch containment liner plate (floor) for a minimum of two of the vertical leak chase channels with holes. Perform examinations of exposed ¼-inch containment liner plate (floor) as required by IWE. Additional excavations will be performed, if necessary, depending upon conditions found at the first two channels.

- Remove ½-inch containment liner insulation panels, adjacent to accessible areas where there are indications of corrosion, to determine the extent of condition of the existing corroded areas of the containment liner plate.

- Perform augmented examinations of the ½-inch containment liner plate behind insulation panels, where loss of material was previously identified, in accordance with IWE-2420.

- Examine 100 percent of the moisture barrier in accordance with IWE-2310 and replace or repair the moisture barrier to meet the acceptance standard in IWE-3510.

The applicant further stated that, “examinations and inspections will be performed in accordance with IWE-2000 and the acceptance standards will be in accordance with IWE-3500.”

The staff finds the corrective actions described above in response to RAI B.2.1.28-1 comprehensive and acceptable because loss of material due to corrosion is being managed in accordance with applicable requirements in ASME Code Section XI, Subsection IWE including enhancements. However, the staff is concerned about the applicant’s timeline for completing the corrective actions. The most recent IWE inspections of the Unit 1 and Unit 2 containment liners were performed in the spring of 2010 and fall of 2009, respectively. These inspections identified the need for augmented inspections and other corrective actions in accordance with the requirements in ASME Code Section XI, Subsection IWE. IWE-2420 requires that augmented inspections be completed during the next inspection period. The period of extended operation for Salem Units 1 and 2 will commence in August 2016 and April 2020, respectively. The staff is concerned that delays in completing the augmented inspections and corrective actions until prior to the start of the period of extended operation may affect the leak tightness of the containment liner.

During a conference call on June 30, 2010, the applicant responded to staff concerns about the timeline for completing the corrective actions by stating that the Unit 1 liner area at the floor junction has already been cleaned and painted and the moisture barrier replaced at the floor and knuckle plate area. No degradation of the Unit 1 liner below the moisture barrier was evident. The Unit 2 liner area at the floor junction will be cleaned and painted and the moisture barrier repaired at the floor and knuckle plate area during the next outage. Degradation of the liner below the moisture barrier will also be investigated during the next outage. The applicant further stated that the corrective actions for insulation removal will start during the next outage but may not be completed if there is corrosion that leads to a wider inspection area. Therefore, the removal of the insulation panels may be scheduled and completed over the next few outages if any corrosion found is limited to small areas and does not compromise the liner plate thickness margin. If sufficient margin is not assured, the inspections will be expedited in accordance with IWE but random samples may get postponed.

The staff considered the applicant's response provided in the June 30, 2010, conference call and finds that the applicant's commitment to complete the corrective actions by August 2016 and April 2020 for Units 1 and 2 too long and can affect the ability of the containment liner plate to perform its intended function during the period of extended operation. Therefore, the staff issued follow-up RAI B.2.1.28-3 on August 3, 2010, requesting that the applicant provide a detailed schedule for performing corrective actions and augmented inspections for the Unit 1 and 2 containment liners that comply with the requirements in ASME Code Section XI, Subsection IWE.

In its response to RAI B.2.1.28-3, dated September 1, 2010, the applicant stated that the examinations of the Salem Unit 1 and Unit 2 containment liners, conducted in 2009 and 2010, comply with the requirements of the 1998 Edition of ASME Code Section XI, Subsection IWE and 10 CFR 50.55a. The examination results, which identified degradation, were entered into the corrective action program and evaluated or repaired to ensure containment integrity. The applicant further stated that the entire Salem Unit 1 containment liner area at the floor junction has been examined, evaluated, cleaned, and painted and the moisture barrier was replaced during the spring of 2010 refueling outage. No degradation of the liner below the moisture barrier was evident. The corrective actions requiring the containment liner insulation removal, in areas where the potential for containment liner corrosion is suspected, will be continued during the next refueling outage. The applicant also stated that the Salem Unit 2 containment liner area at the floor junction will be examined, evaluated, cleaned, and painted and the moisture barrier will be repaired during the next refueling outage, in spring of 2011. Degradation of the liner below the moisture barrier will also be investigated during the next refueling outage.

The applicant in its response to RAI B.2.1.28-3 also stated that the schedule for performing corrective actions and augmented inspections for the Salem Unit 1 and Unit 2 containment liners complies with the requirements of ASME Code Section XI, Subsection IWE and 10 CFR 50.55a. The applicant further stated that augmented inspections for both Salem Unit 1 and 2 will be completed within the next two outages, which will be by 2013. In addition, in response to RAI B.2.1.33-6 concerning minimal leakage onto the containment liner plate from the reactor cavity and fuel transfer canal during the refueling operations, the applicant revised a commitment (Commitment No. 28). This commitment requires that the owner augmented inspections will be performed at the Salem Unit 1 and Unit 2 area of the containment liner, under the fuel transfer canal and behind the containment liner insulation, which are subjected to leaks from the reactor cavity. These owner augmented inspections will be performed on a frequency of once per containment ISI period, starting with the current period. These owner augmented inspections will continue, under the ASME Section XI, Subsection IWE Program, as long as leakage from the reactor cavity or fuel transfer canal is observed between the containment liner and the containment liner insulation, including during the period of extended operation.

The staff finds the applicant's response to RAI B.2.1.28-3 and revision to Commitment No. 28 acceptable because the applicant will perform augmented inspections of the Salem Unit 1 and Unit 2 containment liner in accordance with the ASME Code Section XI, Subsection IWE requirements. Article IWE-2420 of the ASME Code Section XI, Subsection IWE states that, "when examination results require evaluation of flaws or areas of degradation in accordance [with] IWE-3000, and the component is acceptable for continued service, the areas containing such flaws or areas of degradation shall be reexamined during the next inspection period listed [in] the schedule of inspection of IWE-2411 or IWE 2412, in accordance with Table IWE-2500-1, Examination Category EC."

In the operating experience program element of the ASME Section XI, Subsection IWE Program, the applicant discussed sampling inspections of normally inaccessible areas of the steel liner plate located behind the insulation panels around the lower 30 feet of the Unit 1 containment that were completed in 2008.

By letter dated April 15, 2010, the staff issued RAI B.2.1.28-2 requesting that the applicant: (1) describe the sampling methodology used in the 2009 inspection to select the containment liner plate and moisture barrier inspection locations behind the insulating panels and (2) provide the sampling methodology planned for future inspections.

In its response dated May 13, 2010, the applicant stated that random sampling was not used in 2009 to select the locations for inspecting the containment liner plate and the moisture barrier behind the containment liner insulation lagging. The applicant also stated that, "Salem is committed to enhance the ASME Section XI, Subsection IWE, aging management program to require inspections of a sample of the inaccessible containment liner covered by containment liner insulation and lagging prior to the period of extended operation and every 10 years thereafter." The following details of this commitment were provided by the applicant:

<u>Prior to the period of extended operation (PEO)</u>

- A sampling plan will be developed based upon guidance in EPRI TR-107514, "Age Related Degradation Inspection Method and Demonstration: in Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application."

- The population size of containment liner insulation panels in each Unit is approximately 264 panels. A sample size of 57 will meet the statistical requirements of a 95 percent confidence level that 95 percent of the containment liner plate behind the containment liner insulation meets the acceptance criteria of IWE-3500.

- The samples will be randomly selected.

- The examination will be performed by either removing the containment liner insulation panels and performing a visual inspection, or by using a pulsed eddy current (PEC) remote inspection, with the containment liner insulation left in place, to detect evidence of loss of material. If evidence of loss of material is detected using PEC, the containment liner insulation panel will be subsequently removed to allow for visual and UT examinations.

- If acceptance criteria defined in IWE-3500 is not satisfied, the sampling plan will be modified as recommended in EPRI TR-107514.

During the period of extended operation

During the PEO, a reduced sample size will be randomly selected and examined each Containment Inservice Inspection Period contingent upon satisfactory results of the sample examined prior to the PEO.

- One containment liner insulation panel will be selected, at random, for removal from each quadrant, during each of the three Periods in an Inspection Interval. Therefore, a total of 12 containment liner insulation panels will be selected, in each unit, during each ten year Inspection Interval, to allow for examination of the containment liner behind the containment liner insulation.

- The randomly selected containment liner insulation panels in each quadrant will not include containment liner insulation panels previously selected.

The staff finds the applicant’s response to RAI B.2.1.28-2 regarding the size and selection of random sample acceptable because it will ensure that loss of material due to corrosion is being managed in accordance with applicable requirements in ASME Code Section XI, Subsection IWE. The sampling methodology will provide a statistical confidence level of at least 95 percent that the results of the inspection will meet the acceptance criteria of IWE-3500. However, the staff noted that the applicant plans to implement the random sampling plan by August 2016 and April 2020 for Unit 2 too distant.

During a conference call on June 30, 2010, the applicant responded to staff concerns about the timeline for completing the random inspections by stating that the sampling plan will be implemented before 2016 and there will not be a long wait. The commitment is just stating that it will be completed prior to the period of extended operation. It may not be completed in a single outage depending upon what is found. Any corrosion found during examinations is addressed under the IWE requirements. The random sampling plan is not an IWE required inspection.

The staff considered the applicant’s response provided in the June 30, 2010, conference call and finds that the applicant’s commitment to complete the corrective actions prior to the period of extended operation too long and that the ability of the containment liner plate to perform its intended function during the period of extended operation could be adversely affected. The most recent IWE inspections of the Unit 1 and Unit 2 containment liners were performed in the spring of 2010 and fall of 2009, respectively. These inspections identified the need for inspecting inaccessible portions of the containment liners located behind the insulation panels because corrosion was detected in some liner plate sections located behind the insulation. The period of extended operation for Salem Units 1 and 2 will commence in August 2016 and April 2020, respectively. The staff is concerned that corrosion in the inaccessible portions of the liners could remain undetected until the period of extended operation. Section 54.3 of 10 CFR requires that the effects of aging on the functionality of in-scope structures such as the containment liner be managed to maintain the CLB during the period of extended operation. In addition, the RAI response does not clearly identify the time gap between inspections of liner plates located behind 57 randomly selected insulation panels and the subsequent inspections of liner plates located behind the 12 insulation panels. Therefore, the staff has issued follow-up RAI B.2.1.28-4 on August 3, 2010, requesting that the applicant provide a detailed schedule for completing the random inspections and the time gap between inspections of liner plates at 57 randomly selected insulation panels and subsequent inspections at 12 insulation panels.

In its response dated September 1, 2010, the applicant stated that liner plate examination at 57 randomly selected locations are planned to be implemented by August 2016 for both Salem units. It has not yet been finalized whether these liner plate examinations will be scheduled during a single or multiple outages. If the liner plate examinations are scheduled over multiple outages, the number of locations of random liner plate examinations will be approximately equal for each outage. The current plan is to schedule the 57 random liner examinations during earlier available outages and not schedule all of the 57 random liner examinations during the last possible outage prior to August of 2016. The current plans for Salem Unit 1 involve using the following outages: spring 2013, fall 2014, and spring 2016. The current plans for Salem Unit 2 involve using the following outages: fall 2012, spring 2014, and fall 2015. However, in the letter dated September 1, 2010, Commitment No. 28 still states that the 57 random liner examinations of the containment liner plate behind the insulation panels will be completed prior to the period of extended operation.

The staff reviewed the applicant's response to RAI B.2.1.28-4 and compared it with Commitment No. 28. The staff was concerned about the lack of consistency between the RAI response and commitment concerning the schedule for performing the liner plate inspection at 57 locations. The period of extended operation for Salem Units 1 and 2 will commence in August 2016 and April 2020, respectively. The applicant's commitment to complete random inspections of the liner plate for Salem Units 1 and 2 by August 2016 and April 2020, respectively, did not address the staff concern that corrosion in the inaccessible portions of the liners could remain undetected for a long period. Therefore, during a conference call on October, 14, 2010, the staff requested that the applicant revise the schedule for completing the inspections in the license renewal commitments to make it consistent with the response in RAI B.2.1.28-4.

In its letter dated October 19, 2010, the applicant modified Commitment No. 28 of the license renewal commitment list to state:

> All Inspections will be completed by August 2016 for both Salem Units. Approximately one third of the 57 inspections will be completed during each refuel outage (Salem Unit 1 involves the following refuel outages: Spring 2013, Fall 2014, and Spring 2016. Salem Unit 2 involves the following refuel outages: Fall 2012, Spring 2014, and Fall 2015). It is acceptable to perform greater than one third of the inspections in any refuel outage to accelerate the inspection schedule.

The staff finds Commitment No. 28 acceptable because it is consistent with the applicant's response to RAI B.2.1.28-4. In addition, the accelerated plan for inspection of the liner plate behind the insulation panel to be completed by August 2016 and before the period of extended operation will ensure that the effects of aging on the functionality of in-scope structures such as the containment liner be managed to maintain the CLB during the period of extended operation, in accordance with 10 CFR 54.3.

Based on its audit; review of the application; the applicant's responses to RAIs B.2.1.28-1, B.2.1.28-2, B.2.1.28-3, and B.2.1.28-4; and the revision to Commitment No. 28, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and implementation of this 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.2.1.28 provides the UFSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2.

The staff also notes that the applicant committed (Commitment No. 28) to enhance the ASME Section XI, Subsection IWE Program prior to entering the period of extended operation. Specifically, the applicant committed to:

(1) Inspection of a sample of the inaccessible liner covered by insulation and lagging once prior to the period of extended operation and every 10 years thereafter.

(2) Visual inspection of 100 percent of the moisture barrier, at the junction between the containment concrete floor and the containment liner, will be performed in accordance with ASME Section XI, Subsection IWE Program requirements, to the extent practical within the limitation of design, geometry, and materials of construction of the components. The bottom edge of the stainless steel insulation lagging will be trimmed, if necessary, to perform the moisture barrier inspections. This inspection will be performed prior to the period of extended operation, and on a frequency consistent with IWE inspection requirements thereafter.

Prior to the period of extended operation, the applicant committed to examine 57 randomly selected containment liner insulation panels per unit.

> The examination will be performed by either removing the containment liner insulation panels and performing a visual inspection, or by using a pulsed eddy current (PEC) remote inspection, with the containment liner insulation left in place, to detect evidence of loss of material. If evidence of loss of material is detected using PEC, the containment liner insulation panel will be subsequently removed to allow for visual and UT examinations.

During the period of extended operation, the applicant committed to randomly select one containment liner insulation panel for removal from each quadrant during each of the three periods in an inspection interval. By using this process, the applicant will select a total of 12 containment liner insulation panels in each Unit during each 10-year inspection interval, to allow for examination of the containment liner behind the containment liner insulation.

The staff also notes that the applicant committed to enhance the ASME Section XI, Subsection IWE Program by performing specific corrective actions prior to entering the period of extended operation.

As a follow-up to inspections performed during the 2009 refueling outage, the applicant committed to perform the following specific corrective actions on Unit 2 prior to entering the period of extended operation:

- Examine the accessible ¾-inch knuckle plate. If corrosion is observed to extend below the surface of the moisture barrier, excavate the moisture barrier to sound metal below the floor level and perform examinations as required by IWE.

- Perform remote visual inspections of the six capped vertical leak chase channels below the containment floor to determine extent of condition.

- Remove the concrete floor and expose the ¼-inch containment liner plate (floor) for a minimum of two of the vertical leak chase channels with holes. Perform examination of exposed ¼-inch containment liner plate (floor) as required by IWE. Additional excavations will be performed, if necessary, depending upon conditions found at the first two channels.

- Remove ½-inch containment liner insulation panels, adjacent to accessible areas where there are indications of corrosion, to determine the extent of the condition of the existing corroded areas of the containment liner plate.

- Perform augmented examinations of the areas of the ½-inch containment liner plate behind insulation panels, where loss of material was previously identified, in accordance with IWE-2420.

- Examine 100 percent of the moisture barrier in accordance with IWE-2310 and replace or repair the moisture barrier to meet the acceptance standard in IWE-3510.

As a follow-up to inspections performed during the 2010 refueling outage, the applicant committed to perform the following specific corrective actions on Unit 1 prior to entry into the period of extended operation:

- Perform augmented examinations of the ¾-inch containment liner (knuckle plate) at 78-foot elevation in accordance with IWE-2420.

- Perform augmented examinations of the areas of the ½-inch containment liner plate behind insulation panels, where loss of material was previously identified, in accordance with IWE-2420.

- Remove ½-inch containment liner insulation panels, adjacent to accessible areas where there are indications of corrosion, to determine the extent of the condition of the existing corroded areas of the containment liner plate.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI, Subsection IWE 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. 28 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. 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).

3.0.3.2.14 Masonry Wall Program

Summary of Technical Information in the Application. LRA Section B.2.1.32 describes the existing Masonry Wall Program as being consistent, with enhancements, with GALL AMP XI.S5, "Masonry Wall Program." The LRA states the objective of the Masonry Wall Program is to manage aging effects so that the design basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. The LRA further states the Masonry Wall Program is based on guidance from the NRC Bulletin 80-11, "Masonry Wall Design," and NRC IN 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11." The LRA also states that the inspection frequency is 5 years maximum and the scope of the program will be enhanced to include structures that are not monitored under the current term but require monitoring during the period of extended operation. Periodic visual inspections address loss of material and cracking due to age-related degradation of concrete for masonry walls.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S5. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S5.

The staff also reviewed the portions of the "scope of the program," "parameters monitored or inspected," and "detection of aging effects" 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 these enhancements follows.

Enhancement 1. LRA Section B.2.1.32 states an enhancement to the "scope of the program" program element that includes addition of the following SCs that have been determined to be within the scope of license renewal: (1) fire pump house, (2) masonry wall fire barriers, (3) office buildings (clean and controlled facilities buildings), (4) SBO yard buildings, (5) service building, and (6) turbine building. The staff finds this enhancement acceptable because when implemented, the Masonry Wall Program will include all masonry walls within the scope of license renewal and will be consistent with GALL AMP XI.S5 relative to including all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4.

Enhancement 2. LRA Section B.2.1.32 states an enhancement to the "parameters monitored or inspected" program element that includes the addition of an examination checklist for masonry wall inspection requirements. The staff finds this enhancement acceptable because when implemented, the Masonry Wall Program will be consistent with GALL AMP XI.S5 relative to visual inspections for cracking and loss of material, and guidance in the form of a checklist on what to look for and assessment criteria have been added for examination of the masonry walls. This enhancement will help provide assurance that the effects of aging will be adequately managed in a timely manner.

Enhancement 3. LRA Section B.2.1.32 states an enhancement to the "detection of aging effects" program element that includes the specification of an inspection frequency of not greater than 5 years for the masonry walls. The staff finds this enhancement acceptable because when implemented, the Masonry Wall Program will be consistent with GALL AMP XI.S5 relative to the inspection frequency being in line with that recommended in ACI 349.39-96 to help provide assurance that the effects of aging will be adequately managed in a timely manner.

Based on its audit, the staff finds that elements one through six of the applicant's Masonry Wall Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.S5 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.32 summarizes operating experience related to the Masonry Wall Program. The LRA states that actions taken include modifications of some walls, program enhancements, follow-up inspections to substantiate masonry wall analyses and classifications, and the development of procedures for tracking and recording changes to the walls. These actions addressed concerns identified in NRC Bulletin 80-11 and IN 87-67, namely unanalyzed conditions, improper assumptions, improper classification, and lack of procedural controls. The LRA further explains that operating experience is used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Salem. Operating experience from external and internal sources is used. The Masonry Wall Program confirms that masonry walls are in good condition and show insignificant aging or degradation. In 2006, corrective action reports were issued to document, evaluate, and repair: (1) a degraded masonry wall tie rod (missing nut) on the controlled facilities building wall and (2) degraded masonry blocks on a seismic radiation shielding masonry wall in the mechanical penetration room. The LRA also states that the most recent structural monitoring inspections conducted in August 2008 for Salem Unit 1 masonry walls indicated that no walls exhibited signs of significant degradation such as efflorescence or cracking.

The staff reviewed operating experience information in the application and during the onsite audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. 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.2.1.32 provides the UFSAR supplement for the Masonry Wall Program. The staff reviewed this UFSAR supplement description and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 32) to enhance the Masonry Wall Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) include additional buildings and masonry walls as described in LRA Section A.2.1.32, (2) add an examination checklist for masonry wall inspection requirements, and (3) specify an inspection frequency of not greater than 5 years for masonry walls.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the 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. 32 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. 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).

3.0.3.2.15 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.1.33 describes the existing Structures Monitoring Program as being consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program." The LRA explains that the objective of the applicant's Structures Monitoring Program is to manage aging effects of structures or structural components such that there is no loss of intended function. The Structures Monitoring Program was developed and implemented to meet regulatory requirements and guidance of 10 CFR 50.65, "Maintenance Rule"; RG 1.160 (Revision 2); and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes masonry walls evaluated in accordance with NRC Bulletin 80-11, "Masonry Wall Design," and incorporates guidance in NRC IN 87-67, "Lessons Learned from Regional Inspection of Licensee Actions in Response to IE Bulletin 80-11." The LRA also explains that Salem is not committed to RG 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants," but water control structures (service water intake structure and shoreline protection and dike structures) will be monitored consistent with the requirements of RG 1.127, which are incorporated into the applicant's Structures Monitoring Program. The program also relies on plant procedures that are based on guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. The LRA states that structures and structural components are periodically inspected by qualified personnel having a B.S. Engineering degree and/or Professional Engineer license and a minimum of 4 years working on building structures. The LRA also states that protective coatings are not relied upon to manage the effects of aging for structures included within the scope of the AMP, so they are not addressed.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S6. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S6, with the exception of the "detection of aging effects" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

While reviewing the "detection of aging effects" program element, the staff noted that the LRA states that groundwater intrusion has been observed through seismic expansion joints, concrete construction joints, and expansion and shrinkage cracks in the concrete. The LRA also states that underground reinforced concrete structures and structures in contact with raw water are subject to an aggressive environment. Groundwater and raw water chemistry results in 2008 and 2009 indicate chloride levels up to 15,000 parts per million (ppm), which exceeds the GALL Report threshold limit for chlorides (less than 500 ppm). The applicant stated that inspection of below-grade structures will be done when exposed during plant excavations, which are done for construction or maintenance activities. The LRA states that the Structures Monitoring Program has been enhanced to require periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates and assessing its impact on buried structures. The LRA states that the service water intake structure will be monitored to provide a bounding condition and indicator of the likelihood of concrete degradation for inaccessible portions of concrete structures. The LRA also states that there are several subgrade exterior walls that have evidence of past or present groundwater penetration. During the onsite audit, the applicant was asked if it had any plans for inspections of inaccessible reinforced concrete areas prior to the period of extended operation to confirm the absence of concrete degradation. The applicant responded that it did not and that operating experience indicates that there is no evidence of corrosion appearing on the interior surfaces of the concrete structures having inaccessible exterior surfaces. Since the applicant does not have plans for inspections of inaccessible areas, the groundwater is aggressive, there have been several incidences of groundwater penetration into the structures, and the condition of the interior walls may not indicate the condition of the exterior walls, it is unclear to the staff that this is an adequate approach to managing aging of inaccessible concrete structures subjected to aggressive groundwater.

By letter dated April 15, 2010, the staff issued RAI B.2.1.33-3 requesting that the applicant provide: (1) locations where groundwater test samples were/are taken relative to safety-related and important-to-safety embedded concrete walls and foundations and provide historical results (i.e., pH, chloride content, and sulfate content) including seasonal variation of results; and (2) plans for inspections in locations adjacent to embedded reinforced concrete structures where chloride levels exceed limits in the GALL Report, or if no inspections or coring of concrete is planned to evaluate condition of the structures (e.g., presence of steel corrosion or determination of chloride profiles), provide a basis to demonstrate that the current level of chlorides in the groundwater is not causing structural degradation of embedded walls or foundations.

By letter dated May 13, 2010, the applicant responded by providing the groundwater sampling locations as well as the sampling results for 2008, 2009, and 2010. The provided data demonstrated that the wells adequately represent the groundwater present on the site and that the pH and sulfates are within the GALL Report limits, while the chlorides are beyond the limit of 500 ppm. The applicant's response also explained that the chloride levels in the river can be as high as 8,300 ppm, well above the levels found in the groundwater. Based on this fact, the applicant explained that the service water intake structure splash zones, which are exposed to the river water, will serve as a limiting condition or "leading indicator" of potential degradation of below-grade concrete. The splash zone will be inspected on a frequency not to exceed 5 years, and any degradation determined to be due to aggressive chemical attack will be assessed for applicability to below-grade structures and the determination will be made if excavation of below-grade concrete for inspection is necessary. The applicant stated that since 2000, five inspections have been conducted of the Unit 1 and Unit 2 service water intake structures and no indications of aggressive chemical attack have been recorded. Also, the applicant stated that past excavations of below-grade walls have shown the concrete to be in good condition. The applicant further explained that the “leading indicator” approach is adequate because the river water has higher chloride levels than the groundwater, the service water intake structures were built with the same concrete mix as other safety-related structures, and the concrete cover over the reinforcing steel in the service water intake structures is the same as other safety-related structures.

The staff reviewed the applicant’s response and finds it acceptable because it clearly explains why the service water intake structures can be used as an indicator of possible below-grade concrete degradation. The concrete mix design used for the intake structures was the same as the rest of the plant, the concrete cover is the same as the rest of the plant structures, and the intake structures are exposed to a more aggressive environment. These characteristics make the service water intake structures an appropriate indicator of the condition of below-grade concrete. In addition, the intake structures will be inspected on a frequency not to exceed 5 years, which aligns with the GALL Report recommendations. The staff’s concern in RAI B.2.1.33-3 is resolved.

The staff also reviewed the portions of the “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” and “acceptance criteria” program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of the enhancements follows.

Enhancement 1. LRA Section B.2.1.33 states an enhancement to the “scope of the program” program element that includes addition of the following SCs:

- fire house pump
- office buildings (clean and controlled facilities buildings)
- SBO yard buildings
- service building
- switchyard
- turbine building
- transmission towers
- yard structures (foundations for fire water and demineralized water tanks, plant vent radiation monitoring enclosures, turbine crane runway extensions, and manholes)
- building penetrations and pipe encapsulations that perform flood barrier, pressure boundary, shelter, and protection intended functions

- pipe whip restraints and jet impingement/spray shields
- trench covers and sump liners
- masonry walls, including fire barriers
- miscellaneous steel (catwalks, vents, louvers, platforms, etc.)
- vortex suppressor, ice barrier, and marine dock bumper (service water intake structure)
- panels, racks, cabinets, and other enclosures
- metal-enclosed bus
- component supports including electrical cable trays; electrical conduit; tubing; heating, ventilation, and air conditioning (HVAC) ducts; instrument racks; battery racks; and supports for piping and components that are not within the scope of the ASME Section XI, Subsection IWF Program
- duct banks that contain safety-related cables and cables credited for SBO and anticipated transient without scram

The staff finds this enhancement acceptable because when implemented, the Structures Monitoring Program will include all structures considered by the applicant to require monitoring during the period of extended operation and will be consistent with GALL AMP XI.S6 relative to the applicant specifying the structure/aging effect combinations that are managed by its Structures Monitoring Program.

Enhancement 2. LRA Section B.2.1.33 states an enhancement to the "parameters monitored or inspected" program element that includes:

(1) observe concrete structures for reduction in equipment anchor capacity due to local concrete degradation by visual inspections of concrete surfaces around anchors for cracking and spalling

(2) clarify that inspections are performed for loss of material due to corrosion and pitting of additional steel components such as embedments, panels and enclosures, doors, siding, metal deck, and anchors

(3) require visual inspection of penetration seals, structural seals, and elastomers for degradation (hardening, shrinkage, and loss of strength) that will lead to loss of sealing

(4) require the following actions related to the spent fuel pool (SFP) liner: (a) perform periodic structural examination of the fuel handling building per ACI 349.3R to ensure structural condition is in agreement with analysis, (b) monitor telltale leakage and inspect the leak chase system to ensure no blockage, and (c) test water drained from the seismic gap for boron concentration

(5) require monitoring of vibration isolators associated with component supports other than those covered by ASME Code Section XI, Subsection IWF

(6) add an examination checklist for masonry wall inspection requirements

(7) enhance parameters to be monitored for wooden components to include change in material properties and loss of material due to insect damage and moisture damage

The staff finds this enhancement acceptable because when implemented, the Structures Monitoring Program will be consistent with GALL AMP XI.S6 relative to parameters monitored or inspected being commensurate with industry codes, standards, and guidelines. This enhancement will help provide assurance that aging degradation leading to loss of intended functions will be detected and the extent of degradation determined so that the degradation can be adequately managed in a timely manner.

Enhancement 3. LRA Section B.2.1.33 states an enhancement to the “detection of aging effects” program element that includes:

(1) Specify an inspection frequency of not greater than 5 years for the structures including submerged portions of the service water intake structure.

(2) Require individuals responsible for inspections and assessments for structures to have a B.S. Engineering degree and/or Professional Engineer license and a minimum of 4 years experience working on building structures.

(3) Perform periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of 5 years. Groundwater samples in areas of Unit 1 containment structures and the Unit 1 auxiliary building will be tested for boron concentration.

(4) Require supplemental inspections of the affected in-scope structures within 30 days following an extreme environmental or natural phenomena (e.g., large floods, significant earthquakes, hurricanes, and tornadoes).

(5) Perform a chemical analysis of ground or surface water in-leakage when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel.

The staff found this enhancement acceptable because when implemented, the Structures Monitoring Program will be consistent with GALL AMP XI.S6 relative to inspection methods, inspection schedule, and inspector qualifications being commensurate with industry codes, standards, and guidelines, and inclusion of industry and plant-specific operating experience. This enhancement will help provide assurance that the aging degradation will be detected and quantified before there is a loss of intended functions.

Enhancement 4. LRA Section B.2.1.33 states an enhancement to the “acceptance criteria” program element that includes additional acceptance criteria as contained in ACI 349.3R-96. The staff found this enhancement acceptable because when implemented, the Structures Monitoring Program will be consistent with GALL AMP XI.S6 relative to ACI 349.3R-96 being used to provide an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes. This enhancement will help provide assurance that the need for corrective actions will be identified before loss of intended functions.

Based on its onsite audit and review of the applicant’s response to the RAI, the staff finds that elements one through six of the applicant’s Structures Monitoring Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.S6 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.33 summarizes operating experience related to the Structures Monitoring Program. The applicant's technical personnel were interviewed during the onsite audit to confirm that plant-specific operating experience revealed no degradation not bounded by industry experience. The staff reviewed operating experience information in the application and during the onsite audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified operating experience that could indicate that the applicant's program may not be effective in adequately managing aging effects during the period of extended operation. The LRA states that the SFPs have experienced leakage of borated water, leakage of borated water has occurred during refueling outages, and in-leakage of contaminated water was noted during the field walkdown. The staff determined the need for additional clarification, which resulted in the issuance of RAIs.

The LRA states that the SFP at Unit 1 has experienced leakage of borated water that has migrated through small cracks in the concrete to reach the seismic gap between the containment structure and the fuel handling building. The LRA also states that the 2002 test identified evidence of SFP leakage through the wall of the Unit 1 auxiliary building mechanical penetration room. Further investigations revealed that the leak chase and drainage systems were blocked. The LRA further explains that as a result of this blockage, leakage accumulated in small gaps between the stainless steel liner and the concrete and eventually migrated to other locations through penetrations, construction joints, and cracks. During the audit, the staff learned that the seismic gap was confirmed to contain water with radionuclides characteristic of the SFP water and leakage into the seismic gap has continued. Leakage into the telltale drains is occurring at a rate of about 100 gpd. It was unclear to the staff that leakage of the borated water has not resulted in degradation of either the concrete or embedded steel reinforcement that is inaccessible for visual inspection.

By letter dated April 15, 2010, the staff issued RAI B.2.1.33-1 requesting that the applicant: (1) provide historical data on the leakage occurrence and volume, and available information from chemical analysis performed on the leakage; (2) provide the root cause analysis that was used to identify the source of leakage through the liner that has resulted in accumulation of borated water between the liner and concrete, including information on the path of the leakage and structures that could potentially be affected by the presence of the borated water; (3) discuss plans for remedial actions or repairs to address leakage through the SFP liner, and in the absence of a commitment to fix the leakage prior to the period of extended operation, explain how the Structures Monitoring Program, or other plant-specific program, will address the leakage to ensure that aging effects, especially in inaccessible areas, will be effectively managed during the period of extended operation; (4) provide background information and data to demonstrate that the concrete and embedded steel reinforcement have not been degraded by exposure to the borated water and that the liner will not be impacted, and, if experimental results will be used as part of the assessment, provide evidence that the test program is representative of the materials and conditions that exist in the region between the SFP liner and concrete; and (5) if a concrete sampling program (e.g., obtaining concrete cores in region affected) cannot be implemented, please explain why this is not feasible.

In its response dated May 13, 2010, the applicant explained that in 1980, a small leak was discovered in the SFP telltale drains at Unit 1. The leaks were repaired, and the observed leakage was reduced to less than 0.2 gpd. The applicant further explained that in 2002, an active water leak was discovered through an exterior wall of the Unit 1 auxiliary building. Investigation into the source revealed that the SFP telltale drain system was blocked. The applicant explained that this blockage resulted in SFP borated water leakage accumulating behind the SFP liner and ultimately to migration of borated water into the seismic gap between the fuel handling building and the auxiliary building. The blockage was removed from the drain system and since 2003, the leakage through the drain system has been monitored. The applicant stated that the volume of leakage is on average 100 gpd. The applicant also explained that in 2010, evidence of a small active leak was detected in the Unit 2 telltale drain system. After discovering the leak, the applicant verified that the Unit 2 telltale drains were open, and the applicant will continue to monitor and trend the leakage.

The applicant further explained that due to the difficulty associated with verifying the adequacy of the possibly degraded in-place concrete, laboratory testing has been conducted to simulate the effects of borated water leakage on concrete. From these tests, the applicant has predicted a concrete degradation depth of 1.3 inches after 70 years of exposure to borated water. Using this as a limiting value for degradation, the applicant performed a structural assessment of the fuel handling building which showed the structure would continue to perform its intended function through the period of extended operation. The applicant also committed (Commitment No. 33, 5.d) to perform a shallow core sample of the Unit 1 SFP wall where previous inspections have shown ingress of borated water through the concrete. The sample will be examined for degradation from borated water.

The staff reviewed the applicant’s response and found that additional information was required to complete its review. Particularly, based on the information provided, the staff did not agree that the applicant’s assumed degradation after 70 years was an appropriate limiting value. In addition, the staff was not confident the applicant’s structural assessment adequately addressed the effects of borated water leakage on the reinforcing steel. To address these concerns, the staff held a conference call with the applicant on June 30, 2010, and issued follow-up RAI B.2.1.33-5 by letter dated August 3, 2010.

An additional conference call was held with the applicant on August 30, 2010, and by letter dated September 1, 2010, the applicant responded to the follow-up RAI. In its response, the applicant explained the 1.3-inch degradation estimate in more detail. The applicant explained that the estimate was based on a least squares fit of 220 data points collected over 39 months. The applicant further explained that even if boric acid reaches the reinforcing steel, it will not lead to significant degradation due to the minimal oxygen levels. The applicant also revised Commitment No. 33 to include visual inspections of the accessible Unit 1 SFP wall every 18 months. In the response, the applicant addressed the possibility of voids beneath the Unit 1 SFP liner due to degraded concrete. The applicant explained that the impact of voids has been assessed and that the liner was found to be sufficiently ductile to accommodate the load from spent fuel racks, even if the foot of a rack was positioned over an area of concrete degradation. In the response, the applicant also elaborated on the core sample that will be taken at Unit 1. The applicant explained that the core will be at least 4 inches in diameter and approximately 2 feet deep. Reinforcing steel will be exposed for inspection when the core sample is taken. The applicant does not have plans in place to perform additional core samples, unless unexpected adverse findings from the core or future inspections indicate additional core samples are necessary. The applicant also stated that currently there are no indications of active leakage from the SFP through the SFP wall.

The staff reviewed the applicant's response and notes that the applicant has committed to visually inspect the accessible portion of the Unit 1 SFP wall in the sump room on an 18-month interval. Previous inspections have shown ingress of borated water through the concrete at this location. As indicated above, the applicant also committed to remove a concrete core sample from the Unit 1 SFP wall at a location that has previously indicated water leakage. In addition, the staff notes that the applicant will continue to monitor the telltale leakage and inspect the leak chase system at Unit 1 to ensure no blockage. Any water drained from the seismic gap will be tested for boron, chloride, and sulfate concentrations, and pH. The staff also notes that an independent ACI structural assessment of the SFP performed in 2006 by a structural engineer concluded that the concrete appeared to be in good structural condition, and there were no indications of concrete surface expansion due to reinforcement corrosion. The assessment included: (1) a visual inspection of the accessible portions of the fuel handling building exterior walls and sump room; (2) the use of ACI 201.1R-92, "Guide for Conducting a Visual Inspection of Concrete in Service," as inspection guidance; and (3) a comparison of inspection observations against limits in ACI 349.3R. The staff believes the applicant has appropriate programs in place to manage possible degradation of the SFP if it can be assured that the leakage is completely contained within the leak chase channels. However, the staff did not understand how the applicant has concluded that the leakage is contained within the leak chase channels. Therefore, by letter dated October 25, 2010, the staff issued RAI B.2.1.33-7 requesting that the applicant clarify whether through-wall leakage was occurring in any portion of the SFP walls. The staff also discussed this issue with the applicant during conference calls on November 18, 2010, December 8, 2010, and February 17, 2011.

The applicant responded to RAI B.2.1.33-7 by letter dated December 14, 2010, and supplemented its response by letter dated February 25, 2011. In the response, the applicant clarified that a small amount of leakage, approximately one-eighth of a gallon per day, is migrating through the inaccessible east wall of the pool. This is based on sampling of water collected from the seismic gap drain located next to the east wall. The applicant further stated that no evidence of through-wall leakage has been observed on the accessible west wall since the telltale drains were cleared in 2003. The applicant also stated that leakage through the south wall is considered impossible due to the thickness of the wall, which is approximately 39 feet thick. Based on tritium levels of groundwater around the SFP building, the applicant has concluded that leakage from the north wall is not occurring. To address the through-wall leakage and any possible associated concrete degradation, the applicant committed to the following (Commitment No. 33):

(a) Perform periodic structural examination of the fuel handling building per ACI 349.3R to ensure that the structural condition is in agreement with the analysis.

(b) Monitor telltale leakage and inspect the leak chase system to ensure that there is no blockage.

(c) Test water drained from the telltales and seismic gap for boron, chloride, iron, and sulfate concentrations, and pH. Acceptance criteria will assess any degradation from the borated water. Sample readings outside the acceptance criteria will be entered into and evaluated in the corrective action program.

(d) Perform one shallow core sample in each of the Unit 1 SFP walls (east and west) that have shown ingress of borated water through the concrete. The core samples will be examined for degradation from borated water. Also, the core samples (east and west walls) will expose rebar which will be examined for signs of corrosion. The core sample from the west wall will be taken by the end of 2013 and the core sample from the east wall will be taken by the end of 2015.

(e) Perform a structural examination per ACI 349.3R every 18 months of the Unit 1 SFP wall in the sump room where previous inspections have shown ingress of borated water through the concrete.

(f) The applicant also provided the following acceptance criteria for leakage sampled from the telltale drains (west wall) and the seismic gap drain (east wall):

Chemical Analysis	Acceptance Criteria		Frequency for monitoring
	SFP Telltales (West Wall)	Seismic Gap Drain (East Wall)	
pH	6.0 < pH < 7.5	7.0 < pH < 8.5	Monthly
Chloride	≤ 500 ppm	≤ 500 ppm	Every 6 months
Sulfate	≤ 1500 ppm	≤ 1500 ppm	Every 6 months
Boron	Information Only	Information Only	Monthly
Iron	Information Only	Information Only	Every 6 months

The applicant explained that chemistry results that do not meet one of the criteria will be entered into the corrective action program for an investigation and evaluation. The goal of the investigation would be to determine if the observed change could lead to an increase in potential degradation. The applicant also explained that to date, no indications of rebar degradation, such as rust staining or concrete spalling, have been observed. The staff reviewed the applicant’s response and noted that the applicant has committed to take concrete core samples from both the east and west walls, which will expose the rebar for investigation. These samples will provide information about the condition of concrete exposed to borated water leakage, and any indications of degradation will be investigated through the applicant’s corrective action program. The staff also noted that the applicant has committed to visually inspect the accessible west wall every 18 months and to monitor the leakage for any indications of changes which could lead to increased rates of degradation.

The staff also reviewed the applicant’s acceptance criteria for the pH and other chemicals sampled at the spent fuel tank telltales and seismic gap drains as noted above. The acceptance criteria value for the water sampled at telltales is set to be greater than 6.0 or below 7.5. This pH acceptance criterion has been set based on the data collected since 2003.

In its supplemental response to RAI B.2.1.33-7, the applicant stated that the water collected from telltales enters the carbon steel leak chase channels located behind the stainless steel liner plate either directly from the liner seam welds or indirectly by migrating over concrete from the cracks in the plug welds, which are not backed by the leak chase channels. The staff agrees with the applicant’s explanation that the pH of the water from telltales is affected by the proportion of the water leaking from the seam welds (which will not contact concrete) relative to the leakage from the plug welds (which will contact and react with concrete, increasing the pH). The pH of the water would be more than 7.0 if all the leakage was from the plug welds, and there was no leakage from the stainless steel liner seam welds as is the case at the seismic gap drain. The water collected at the seismic gap drain passes through the concrete construction joint and reacts with concrete resulting in a higher pH.

The applicant has stated in its response that rebar embedded in concrete will not experience any significant corrosion on the basis that local conditions at the interface of borated water and rebar will be deaerated because: (1) borated water that leaks through the stainless steel liner will be partially deaerated as it reacts with and corrodes the carbon steel leak chase channels, (2) oxygen in the borated water that reaches the embedded rebars by traveling through cracks in concrete will be quickly consumed during initial oxidation reaction with the rebar, and (3) the oxygen that is consumed will not be replenished since the water migration path to rebar is relatively stagnant. The staff finds this explanation reasonable and acceptable. The staff also reviewed the technical literature and found that the corrosion rates for the rebar exposed to borated water with the concentration used in the SFP and temperature of about 32 °C (90 °F) in a deaerated environment is very low and consistent with the values used by the applicant in its analyses.

The staff also noted that the carbon steel leak chase channels may corrode over time from exposure to the borated water. This is acceptable because degradation of these channels has no impact on the structural integrity of the SFP or fuel handling building structure. The leak chase channels' sole function is to collect SFP water leakage and route it to the sump via telltales. The channels have no structural function. In addition, the applicant plans to monitor the channels and keep them clean to allow the flow of water to the telltales.

The staff finds the applicant's approach for managing degradation of the SFP building due to borated water leakage acceptable because the applicant has plans in place to verify the adequacy of the concrete and rebar exposed to leakage via core bores. If degradation is detected, the condition will be entered into the corrective action program and addressed. The applicant will also monitor the leakage to confirm that leakage amount and chemistry is not changing during the period of extended operation. The staff has made the two core samples a license condition for Unit 1, along with follow-on reporting requirements that provide results, recommendations, and any planned actions to the NRC, as such sampling and reporting would provide assurance that the applicant can verify the adequacy of concrete and rebar exposed to borated water. The leakage has been occurring since 2003; if no degradation has occurred after 12 years when the cores are taken in 2015, it provides reasonable assurance that degradation will not occur during the period of extended operation. The staff's concern regarding SFP leakage, covered in RAI B.2.1.33 and follow-up RAIs B.2.1.33-5 and B.2.1.33-7, is resolved and Open item OI 3.0.3.2.15-1 is closed.

The LRA states that leakage of borated water has occurred in Salem Units 1 and 2 reactor cavities during refueling outages, but the leaks have been contained within the containment building. In April 2006, visual structural examinations of the accessible portions of the containment reinforced concrete structures for Units 1 and 2 indicated that the concrete was apparently in good structural condition; however, it is unclear to the staff that leakage of the borated water has not resulted in degradation of either the concrete or embedded steel reinforcement that is inaccessible for inspection.

By letter dated April 15, 2010, the staff issued RAI B.2.1.33-2 requesting that the applicant: (1) provide historical data on the leakage occurrence and volume, and available information from chemical analysis performed on the leakage; (2) provide the root cause analysis that was used to identify the source of leakage, including information on the path of the leakage and structures that could potentially be affected by the presence of the borated water; (3) discuss plans for remedial actions or repairs to address leakage, and in the absence of a commitment to fix the leakage prior to the period of extended operation, explain how the Structures Monitoring Program, or other plant-specific program, will address the leakage to ensure that aging effects, especially in inaccessible areas, will be effectively managed during the period of extended operation; and (4) provide background information and data to demonstrate that concrete and embedded steel reinforcement potentially exposed to the borated water have not been degraded, and if experimental results will be used as part of the assessment, provide evidence that the test program is representative of the materials and conditions that exist.

By letter dated May 13, 2010, the applicant explained that evidence of leakage has been detected in Unit 1 since the 2005 refueling outage and since the 2000 refueling outage in Unit 2. The leakage only occurs when the reactor cavity and fuel transfer canal are flooded. Active leaks have only been observed sporadically with measured rates less than 100 drops per minute. The applicant further explained that the probable source of leakage is very small cracks in the reactor cavity or fuel transfer canal liner. The majority of this leakage enters the leak collection chases; however, where the fuel transfer canal exits containment, leakage migrates through the concrete and down the sides of the containment liner behind the lagging. The applicant stated that the leakage has the potential to impact the reactor cavity and fuel transfer canal reinforced concrete structures, as well as the containment liner. The impact of the leakage on the containment liner will be addressed by the ASME Section XI, Subsection IWE Program.

To address the possible concrete degradation, the applicant enhanced the Structures Monitoring Program to perform periodic inspection of the telltale drains associated with the reactor cavity and fuel transfer canal. The applicant stated that keeping the telltales free of blockage will ensure that water between the liner and concrete will only contact the concrete for short durations. The applicant explained that remedial actions are not needed based on the short duration of the refueling activities and concrete exposure to borated water. The applicant also stated that the findings associated with the fuel handling building concrete degradation research are directly applicable to the reactor cavity leakage. Using the assumed degradation from the fuel handling building assessment and adjusting the time of exposure assuming the concrete is only exposed to water during refueling outages, the applicant calculated an expected depth of degradation of 0.29 inches. The applicant stated that this degradation would not approach the reinforcing steel and the leakage has no impact on the intended function of the reactor cavity structures during the period of extended operation.

The staff reviewed the applicant’s response and found that additional information was required to complete its review. Particularly, based on the information provided, the staff did not agree that the applicant’s assumptions were correct regarding concrete degradation when exposed to borated water. In addition, the staff did not have a clear understanding of the postulated leakage path, or what corrective actions were planned to address the leakage. To address these concerns, the staff held a conference call with the applicant on June 30, 2010, and issued follow-up RAI B.2.1.33-6 by letter dated August 3, 2010. The RAI requested that the applicant discuss any corrective actions planned to stop the borated water leakage and any plans for inspecting inaccessible portions of the containment liner located in areas of postulated leakage.

An additional conference call was held with the applicant on August 30, 2010, and by letter dated September 1, 2010, the applicant responded to the follow-up RAI. The applicant stated that there are currently no plans to prevent the flow of borated water down the containment liner since leakage has been intermittent and when panels were removed, the liner was in good condition. The applicant further stated that the source of the leakage has not been determined and that the leakage has been small and varies between outages. The applicant committed to perform augmented inspections under the fuel transfer canal, where the containment liner is subjected to leakage. These inspections will be performed once per containment ISI period, as long as leakage is observed.

The staff reviewed the applicant's response and finds it acceptable because it explains that the leakage is minimal and contained in the area below the fuel transfer canal. It also explained that the containment liner was shown to be in good condition and will continue to be inspected every inspection period when leakage is identified. These actions and commitments provide reasonable assurance that aging of the containment liner due to the fuel transfer canal leakage will be adequately managed during the period of extended operation. In regards to the possible degradation of the concrete structures due to the leakage, the staff finds the applicant's response acceptable. The applicant has programs in place to detect degradation of the SFP, which due to higher volumes and more frequent leakage, should be a leading indicator of any degradation that may occur in the refueling cavity. If any degradation is noted in the SFP, the condition will be entered in the applicant's corrective action program and the impact on the refueling cavity will be analyzed. The leading indicator of the SFP along with the Structures Monitoring Program visual inspections on a 5-year frequency provide reasonable assurance that aging of the containment internal concrete structures will be properly managed during the period of extended operation. The staff's issues in RAI B.2.1.33-2 and follow-up RAI B.2.1.33-6 are resolved.

During the field walkdown with the applicant's technical staff on February 12, 2010, the staff noticed minor indications of degradation in several areas (e.g., cracking, efflorescence, leaching, and water). At Salem Unit 1 auxiliary building elevation 64 (below groundwater level), there was evidence of water in-leakage through the wall and the area was roped off as an exclusion zone. The applicant was asked about this and informed the staff that the source of the contamination was from in-leakage of groundwater and that the groundwater had picked up the contamination external to the wall.

By letter dated April 15, 2010, the staff issued RAI B.2.1.33-4 requesting that the applicant provide information on how the in-leakage of contaminated groundwater will be addressed under the corrective action program.

By letter dated May 13, 2010, the applicant explained that the leakage has been identified at shrinkage cracks in the below-grade auxiliary building concrete wall. An initial inspection and evaluation has been conducted and it has been concluded that the current condition does not adversely impact the structure's intended function. The response also explained that the crack area is currently in the corrective action program to be cleaned so a detailed engineering inspection can be performed to ensure long term aging issues are identified and any other required corrective actions can be performed. In addition, the applicant explained that the Structures Monitoring Program includes an enhancement to perform a chemical analysis of in-leakage, when the leakage is significant or there is reason to believe the leakage may be damaging concrete elements or the reinforcing steel.

The staff finds this acceptable because the applicant explained that the leakage is being tracked in the corrective action program and there are plans in place to perform a detailed engineering inspection to identify, and address, possible aging concerns which may negatively affect the structure's intended function during the period of extended operation. In addition, as discussed above in the response to RAI B.2.1.33-3, the applicant is using the condition of concrete in the service water intake structures as a “leading indicator” of possible degradation of the inaccessible below-grade concrete structures. The staff’s concern in RAI B.2.1.33-4 is resolved.

Based on its audit, review of the application, and review of the applicant’s response to RAIs as discussed above, the staff finds that operating experience related to the applicant’s program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. 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.

<u>UFSAR Supplement</u>. LRA Section A.2.1.33 provides the UFSAR supplement for the Structures Monitoring Program. The staff reviewed this UFSAR supplement description and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 33) to enhance the Structures Monitoring Program prior to entering the period of extended operation. Specifically, the applicant committed to:

(1) Include additional SCs as described in LRA Section A.2.1.33.

(2) Observe concrete structures for a reduction in equipment anchor capacity due to local concrete degradation. This will be accomplished by visual inspection of concrete surfaces around anchors for cracking and spalling.

(3) Clarify that inspections are performed for loss of material due to corrosion and pitting of additional steel components, such as embedments, panels and enclosures, doors, siding, metal deck, and anchors.

(4) Require inspection of penetration seals, structural seals, and elastomers for degradations that will lead to a loss of sealing by visual inspection of the seal for hardening, shrinkage, and loss of strength.

(5) Require the following actions related to the SFP liner: (a) perform periodic structural examination of the fuel handling building per ACI 349.3R to ensure the structural condition is in agreement with the analysis, (b) monitor telltale leakage and inspect the leak chase system to ensure no blockage, and (c) test water drained from the seismic gap and telltales, and (d) perform core samples at the construction joints in east and west walls.

(6) Require monitoring of vibration supports other than those covered by ASME Code Section XI, Subsection IWF.

(7) Add an examination checklist for masonry wall inspection requirements.

(8) Enhance parameters monitored for wooden components to include: change in material properties, loss of material due to insect damage, and moisture damage.

(9) Specify an inspection frequency of not greater than 5 years for structures including submerged portions of the service water intake structure.

(10) Require individuals responsible for inspections and assessments for structures to have a B.S. Engineering degree and/or Professional Engineer license and a minimum of 4 years experience working on building structures.

(11) Perform periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of 5 years. Groundwater samples in the areas adjacent to the Unit 1 containment structure and Unit 1 auxiliary building will also be tested for boron concentration.

(12) Require supplemental inspections of the affected in-scope structures within 30 days following extreme environmental or natural phenomena (e.g., large floods, significant earthquakes, hurricanes, and tornadoes).

(13) Perform a chemical analysis of ground or surface water when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel.

(14) Enhance implementing procedures to include additional acceptance criteria details specified in ACI 349.3R-96.

(15) When the reactor cavity is flooded, periodically monitor the telltales associated with the reactor cavity and refueling canal for leakage. If telltale leakage is observed, then the pH of the leakage will be measured to ensure that concrete reinforcement steel is not experiencing a corrosive environment. In addition, periodically inspect the leak chase system as associated with the reactor cavity and refueling canal to ensure the telltales are free of significant blockage. Inspect concrete surfaces for degradation where leakage has been observed, in accordance with this program.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its onsite 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 through Commitment No. 33 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. 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 recommended by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B.2.1.34 describes the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as consistent, with enhancements, with GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The applicant stated RG 1.127 is implemented through the Structures Monitoring Program (10 CFR 50.65) and is based on the guidance provided in RG 1.127 and ACI 349.3R. The applicant stated that Salem is not committed to RG 1.127; however, Salem has been implementing the guidance of RG 1.127 to the structures within the scope of license renewal. These structures include the service water intake structure and shoreline protection and dike structures (including the outer walls of the circulating water intake structure). The applicant further stated that accessible structures are monitored on a frequency of 5 years consistent with the frequency for implementing the requirements of the 10 CFR 50.65 Maintenance Rule and annual inspections for shoreline protection structures. The program will be enhanced to include an inspection frequency of 5 years for SCs submerged in water and annual inspections for shoreline protection structures.

The applicant stated safety and performance instrumentation such as seismic instrumentation, horizontal and vertical movement instrumentation, uplift instrumentation, and other instrumentation described in RG 1.127 are not incorporated in the design of Salem water-control structures. Thus, inspection activities related to safety and performance instrumentation are not applicable and are not specified in the implementing procedures.

As noted below, the applicant stated that prior to the period of extended operation the program will be enhanced to provide reasonable assurance that water-control aging effects will be adequately managed during 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 also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S7. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S7.

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.2.1.34 states an enhancement to the "parameters monitored or inspected" program element. The LRA explains that procedures will be enhanced for monitoring wooden components to include change in material properties and loss of material due to insect damage and moisture damage. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 2. LRA Section B.2.1.34 states an enhancement to the "parameters monitored or inspected" program element. The LRA explains that procedures will be enhanced for monitoring elastomers to include hardening, shrinkage, and loss of strength due to weathering and elastomer degradation. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 3. LRA Section B.2.1.34 states an enhancement to the "detection of aging effects" program element. The LRA explains that procedures will be enhanced to require inspections for submerged concrete structural components to be performed by dewatering a pump bay or by a diver if the pump bay is not dewatered. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 4. LRA Section B.2.1.34 states an enhancement to the “detection of aging effects” program element. The LRA explains that procedures will be enhanced to specify an inspection frequency of not greater than 5 years for in-scope structures including submerged portions of the service water intake structure. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 5. LRA Section B.2.1.34 states an enhancement to the “detection of aging effects” program element. The LRA explains that procedures will be enhanced to require supplemental inspections of the in-scope structures within 30 days following extreme environmental or natural phenomena (e.g., large floods, significant earthquakes, hurricanes, and tornadoes). The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Based on its audit, the staff finds that elements one through six of the applicant’s RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.S7 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.34 summarizes operating experience related to the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The LRA discusses degradation of the plant’s service water intake structure. In 2004, the applicant stated a 2-inch separation was observed between the concrete deck slab of the cofferdam and the exterior wall of the service water intake structure due to differential settlement of the cofferdam concrete deck slab and the service water intake structure foundation wall. The base plate of the support post for the security fencing located on the cofferdam slab was severely corroded due to ponding of water on the concrete deck slab. The exterior concrete masonry wall that is part of the security barrier exhibited cracking of the blocks. There was no structural degradation noted on the service water intake structure reinforced concrete exterior wall except that the concrete coating was separating from the wall. Immediate action was to provide temporary support of the security fencing, power washing of the area, and documenting the conditions. The applicant stated that the condition was evaluated by site engineering and determined not to affect the intended function of any safety-related systems or structures. This area of the facility was subject to an aggressive environment (i.e., river water), which contributed to these degradations. The applicant stated corrective action was taken to repair the degraded conditions in accordance with plant specifications and procedures. In 2002, during the performance of preventive maintenance walkdowns to support condition monitoring of the service water intake structure, the applicant stated that spalling had occurred on the exterior concrete wall near watertight doors SW-1 and SW-5. There was exposure of the rebar as a result of the spalling and corrosion on the rebar was noted. The condition was evaluated by design engineering and repaired in accordance with station specifications. The applicant stated as a follow-up to this condition report, a walkdown inspection of the area was performed in 2004. It was noted that the spalling condition had been repaired and no indication of additional degradation in the structure was present.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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.

<u>UFSAR Supplement</u>. LRA Section A.2.1.34 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 notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 34) to ongoing implementation of the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing aging of applicable components during the period of extended operation.

The applicant also committed (Commitment No. 34) to enhancing the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program prior to the period of extended operation. Specifically the applicant committed to:

(1) enhance parameters monitored for wooden components to include change in material properties and loss of material due to insect damage and moisture damage

(2) enhance parameters monitored for elastomers to include hardening, shrinkage, and loss of strength due to weathering and elastomer degradation

(3) enhance the inspection requirement for submerged concrete structural components to require that inspections be performed by dewatering a pump bay or by a diver if the pump bay is not dewatered

(4) specify an inspection frequency of not greater than 5 years for structures including submerged portions of the service water intake structure

(5) require supplemental inspections of the in-scope structures within 30 days following extreme environmental or natural phenomena (e.g., large floods, significant earthquakes, hurricanes, and tornadoes)

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. 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 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. 34 prior to the period of extended operation would

make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.40 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent, with an exception, with GALL AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that its program manages the loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The applicant also stated that a representative sample of cable connections within the scope of license renewal will be selected for one-time testing prior to the period of extended operation. The applicant further stated that the scope of the sampling program will consider application (medium- and low-voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.) and that the technical basis for the sample selection will be documented. The applicant also stated that the one-time test used to confirm the absence of an aging effect with respect to electrical cable connection stressors will be a specific, proven test for detecting loose connections, such as thermography or contact resistance measurement, as appropriate for the application.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E6. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.E6, with the exception of the "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. Based on its audit, the staff finds that the "preventive actions" and "acceptance criteria" program elements of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are consistent with the corresponding program elements of GALL AMP XI.E6 and, therefore, acceptable.

The staff also reviewed the portions of the "scope of the program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "corrective actions" program elements 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.

Exception. LRA Section B.2.1.40 states an exception to the "scope of the program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "corrective actions" program elements. The applicant stated that the exception for this AMP is that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is consistent with the GALL Report, as modified by the

September 6, 2007, proposed revision of Interim Staff Guidance (ISG) LR-ISG-2007-02. The ISG recommends that, prior to the period of extended operation, a one-time inspection on a representative sample basis is warranted to ensure that either aging of metallic cable connections is not occurring and/or that the existing preventive maintenance program is effective, such that a periodic inspection program is not required. The one-time inspection verifies that loosening and/or high resistance of cable connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation are not occurring and, therefore, periodic inspections are not required. Subsequent to the applicant's LRA, a notice of availability of the final LR-ISG-2007-2 was published in the *Federal Register* on December 23, 2009 (74 FR 68287). Therefore, the staff evaluated the AMP and LRA Sections B.2.1.40 and A.2.1.40 based on the staff's aging management guidance provided by the final LR-ISG-2007-02 and GALL AMP XI.E6.

The staff finds the exception acceptable because the identified program elements are in accordance with GALL AMP XI.E6, as modified by the final LR-ISG-2007-02, for compliance with the requirements of 10 CFR 54.21(a)(3) to demonstrate that the effects of aging for certain electrical cable connections not otherwise subject to the requirements of 10 CFR 50.49 will be adequately managed during the period of extended operation.

Based on its audit and review of LRA Section B.2.1.40, the staff finds that elements one through six of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, with acceptable exception, are consistent with the corresponding program elements of GALL AMP XI.E6 as modified by the final LR-ISG-2007-02 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.40 summarizes operating experience related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Although a new program, the applicant stated that plant operating experience has successfully demonstrated the identification of loose connections through the effective use of thermography. The applicant also stated that plant operating experience is in alignment with industry experience, in that electrical connections have not experienced a high degree of failures and that existing plant installation and maintenance practices are effective. The applicant further stated that operating experience provides objective evidence that thermography will detect and/or monitor loose electrical connections. The applicant concluded that thermography and the corrective action program will resolve issues prior to the loss of intended function and, therefore, there is sufficient confidence that the implementation of the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will effectively confirm the absence of aging degradation of metallic cable connections. Referencing the LRA operating experience examples, the applicant concluded that the effects of aging and aging mechanisms are being adequately managed. The applicant stated that these examples provide objective evidence that the AMP will be effective in resolving problems prior to loss of function.

The staff reviewed the operating experience 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of operating experience for the period 2000 through November 2009. Databases were searched using various keyword searches and then reviewed by technical auditor staff. Databases searched include licensee event reports, event notifications, inspection findings, and inspection reports.

During its review, it was not clear based on the applicant's operating experience discussion that the referenced LRA operating experience examples were representative, in that the search methodology and criteria are not discussed, such as databases searched, connection types, timeframe, or connection stressors such as application, loading, and environment. Based on the above, the staff could not conclude that the applicant's program will be effective in adequately managing aging effects during the period of extended operation. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

By letter dated June 10, 2010, the staff issued RAI B.1.2.40-1 requesting that the applicant explain the evaluation methods and search criteria used to select the representative examples in LRA B.2.1.40 and the associated basis document. The applicant responded by letter dated July 8, 2010, and stated that a significant source for operating experience is found in historical plant documentation records, including maintenance work records, condition reports and corrective action evaluations, external operating experience evaluations, and engineering evaluations of regulatory correspondence such as NRC INs and GLs. The applicant also stated that operating experience for existing programs is found in system and program assessment documentation such as system/program manager notebooks, system health reports, program health reports and performance indicators, self assessments, and third party assessments. The applicant further stated that no limit was specified for historical record searches although it was preferred to use more recent examples (since 2000) with the primary focus to identify operating experience where age-related degradation was precluded, mitigated, identified during performance testing, or otherwise detected or corrected prior to loss of component intended functions. In addition, the applicant stated that operating experience that indicated an AMP or aging management activity may not be effective was also considered, including potential enhancements to improve the program or activity that demonstrated that feedback from past operating experience results in appropriate program enhancements to improve aging management effectiveness. The applicant stated that specific operating experience was selected for discussion in the LRA regarding the AMP and that these examples were peer reviewed by a license renewal project manager and the site subject matter expert and approved by the technical lead.

With the information provided by the applicant's RAI response, the staff finds the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program acceptable because the applicant provided a more detailed description of the data searched, evaluation methods, and search criteria employed by the applicant in selecting the representative operating experience examples. The operating experience provided by the applicant and identified by the staff's independent database search is bounded by industry operating experience with no previously unknown aging effects identified by the staff. Based on the applicant's RAI response and the staff's independent operating experience reviews, the staff concludes that the applicant's program operating experience is consistent with the guidance of SRP-LR Section A.1.2.3.10 such that there is reasonable assurance that the operating experience and conclusions provided by the applicant are representative of plant operating experience and that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will effectively manage the effects of aging and aging mechanisms during the period of extended operation. The staff's concern described in RAI B.2.1.40-1 is resolved.

Based on its audit, review of the LRA, and the review of the applicant's response to RAI B.2.1.40-1, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. 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.2.1.40 provides the UFSAR supplement for the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2 as modified by LR-ISG-2007-02. The staff also notes that the applicant committed (Commitment No. 40) to implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff determines those program elements for which the applicant claimed consistency with the GALL Report and final LR-ISG-2007-02 are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with exception, is adequate to manage the aging effects for which the LRA credits it. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Metal Fatigue of Reactor Coolant Pressure Boundary

Summary of Technical Information in the Application. LRA Section B.3.1.1 describes the existing Metal Fatigue of Reactor Coolant Pressure Boundary Program as consistent, with enhancements, with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." LRA Section B.3.1.1 states that the program monitors and tracks the number of critical thermal and pressure transients to ensure that the cumulative usage factors (CUFs) for the reactor vessel, the pressurizer, the SGs, Class 1 and non-Class 1 piping, and Class 1 components subject to the reactor coolant, treated borated water, and treated water environments remain less than 1.0 through the period of extended operation. The applicant further stated that the program determines the number of transients that occur and uses the software program WESTEMS™ to compute CUFs for select locations. The applicant also stated that the program requires generating periodic fatigue monitoring reports on an annual basis, which includes a listing of transient events, cycle summary event details, CUFs, a detailed fatigue analysis report, and a cycle projection report. In addition, the applicant stated that if the fatigue usage for any location increases beyond expected, based on cycle accumulation trends and projections, or if the number of cycles would approach their limit, the corrective action program would be used to evaluate the condition and determine the corrective action.

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

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP X.M1. As discussed in the AMP Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP X.M1.

The staff notes that LRA Sections A.3.1.1 and B.3.1.1, under the discussion of the Metal Fatigue of Reactor Pressure Boundary Program, state that WESTEMS™ computes CUFs for select locations. Furthermore, LRA Section 4.3.1 mentions that data from the WESTEMS™ fatigue monitoring software were reviewed to determine the number of pressurizer heatups and cooldowns. In addition, LRA Section 4.3.4.2 credits the WESTEMS™ code for the evaluation of fatigue for the pressurizer and surge line locations.

The staff identified concerns regarding the results determined by WESTEMS™ as a part of the ASME Code fatigue evaluation process as used in new reactor licensing. For example, Westinghouse's response to NRC questions regarding the AP1000 Technical Report (ADAMS Accession No. ML102300072) describes the ability of users to modify intermediate data (peak and valley stresses/times) used in the analyses. In addition, a response provided by Westinghouse on August 20, 2010 (ADAMS Accession No. ML102350440) describes different approaches for summation of moment stress terms. The staff noted that these concerns, raised by the staff on other licensing reviews, may have an impact on the calculated CUF used for license renewal. Furthermore, the possibility that such user modifications could result in non-conservative evaluations of CUF values formed, in part, the basis for the staff's conclusions in Regulatory Issue Summary (RIS) 2008-30, "Fatigue Analysis of Nuclear Power Plant Components," dated December 16, 2008. The RIS notes that simplification of the analysis requires a great deal of judgment by the analyst to ensure that the simplification still provides a conservative result. The staff recognizes that WESTEMS™ has been developed under a formal quality assurance program with supporting technical bases; however, it is difficult to ascertain the accuracy or conservatism of a location-specific application of WESTEMS™ given that a variety of analyst judgments may still be applied to the software outputs by the user on a case-specific basis. This concern was identified as Open Item OI 4.3.4.2-1.

By letter dated November 22, 2010, the staff issued RAI 4.3-07 requesting that the applicant provide the following:[1]

- [Bullet #1] - Clarify how WESTEMS™ is used at each Salem unit, especially with regard to the Metal Fatigue of Reactor Pressure Boundary Program. Specifically, what transients and locations are monitored by WESTEMS™, what WESTEMS™ stress modules are used, and are the stress models used at each Salem unit identical?

- [Bullet #2] - Describe whether the issues raised in ADAMS Accession Nos. ML102300072 dated August 13, 2010, and ML102350440 dated August 20, 2010, are applicable to each Salem WESTEMS™ monitored location. If not, please describe the reasons those issues are not applicable.

- [Bullet #3] - For each location monitored by WESTEMS™, describe the historical fatigue analyses of record starting from the original ASME Code Section III design basis fatigue

[1]The "Bullet" identifiers for each RAI subpart were created by the applicant in its response to the RAI.

analysis of record. For each follow-on analysis, please describe the reason for the reanalysis, whether the evaluation was referenced in the CLB, and whether an updated ASME Code Section III Design Specification and Code Reconciliation were performed in accordance with ASME Code Section III requirements. Please describe how these analyses are reflected in the results tabulated in [LRA] Tables 4.3.1-1, 4.3.4-1, 4.3.7-1, and 4.3.7-2.

- [Bullet #4] - Describe the environmentally-assisted fatigue (EAF) analyses performed for each monitored location, if any.

- [Bullet #5] - Describe the differences between the stress models used in WESTEMS™ and the stress models used in the currently governing fatigue analysis of record and the EAF analysis of record (if any) for each monitored location.

- [Bullet #6] - Describe how the transient counting results tabulated in [LRA] Tables 4.3.1-3 and 4.3.1-4 are incorporated into the fatigue results shown in [LRA] Tables 4.3.7-1 and 4.3.7-2.

The staff also requested in RAI 4.3-07 that benchmarking evaluations be performed for two of the limiting locations monitored in the Salem WESTEMS™ application using the same input parameters and assumptions as those used in traditional ASME Code Section III CUF calculations for each location. It was further requested that if traditional ASME Code Section III CUF calculations do not exist for either of the selected locations, they should be developed using techniques that allow independent comparison with the WESTEMS™ results. The intent of this benchmarking evaluation was to confirm that the results of the WESTEMS™ models, including any analyst judgments, are acceptable and comparable to traditional ASME Code Section III CUF analyses for the selected monitored locations.

The pressurizer surge nozzle and the 1.5-inch boron injection tank (BIT) line locations were selected as the two limiting locations for the benchmarking evaluations that the applicant indicated are monitored in the Salem WESTEMS™ application. The staff further requested the applicant to provide a summary of the benchmarking evaluations for each of these two components including the following information:

- [Benchmarking Bullet #1] - A comparison of the calculated stresses and CUF using WESTEMS™ to the same results from traditional ASME Code Section III CUF calculations for all transient pairs representing at least 75 percent of the total CUF from the ASME Code Section III CUF calculations. One comparison for each unique stress model used in WESTEMS™ for each selected location was considered to be sufficient.

- [Benchmarking Bullet #2] - Describe the differences in the results between the WESTEMS™ evaluation and the ASME Code Section III CUF calculations for each selected location, and provide a justification for acceptability of the differences.

The applicant responded to RAI 4.3-07 by letter dated December 21, 2010. During its review of the RAI response and as described below, the staff determined that it would audit the calculations performed by the applicant to verify the statements and conclusions in the response. The audit was conducted on January 18 and 19, 2011. During the audit, the staff identified a need for additional information (identified as “Audit Questions No. 1 to 6”), which the applicant provided responses to by letter dated January 31, 2011. The staff concluded its audit on February 8, 2011.

The following is a discussion of the staff's evaluation of the applicant's responses to the staff's RAIs and audit questions.

RAI 4.3-07, Bullet #1

In its response dated December 21, 2010, the applicant addressed RAI 4.3-07, Bullet #1 by stating that WESTEMS™ was used to prepare the EAF calculations for the following locations:

(1) pressurizer surge line nozzle safe end to pipe weld
(2) surge line hot leg nozzle to pipe weld
(3) RHR/accumulator nozzle to pipe weld
(4) normal and alternate charging line nozzles to pipe weld
(5) safety injection BIT nozzle to pipe weld

In addition to these calculations, the applicant stated that it will use WESTEMS™ as an online monitoring tool as a part of its Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated that online plant data will be monitored by WESTEMS™, which will then be used by WESTEMS™ to calculate stresses at specific locations for Units 1 and 2. The applicant further stated that WESTEMS™ will also calculate stress time histories for the monitored locations and calculate CUF according to the methods defined in ASME Code Section III, subparagraph NB-3200 (NB-3200).

The applicant also stated that its Metal Fatigue of Reactor Coolant Pressure Boundary Program will use manual cycle counting to monitor design-basis transients for Class 1 components not monitored by WESTEMS™. The applicant stated that it does not currently use WESTEMS™ to count transients for Class 1 components not monitored by WESTEMS™. WESTEMS™ is only used to monitor the plant parameters (e.g., flow rates, pressures, temperatures, etc.) that are affected by thermal transients and are important for calculating stresses and CUF at the monitored locations.

The staff noted that Enhancement 2 of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program states that a software program will be used to automatically count transients and calculate CUF on "select components," which are the following locations monitored by WESTEMS™:

(1) pressurizer surge line nozzle safe end to pipe weld
(2) surge line hot leg nozzle to pipe weld
(3) RHR/accumulator nozzle to pipe weld
(4) normal and alternate charging line nozzles to pipe weld
(5) safety injection BIT nozzle to pipe weld
(6) auxiliary feedwater nozzle transition piece (for Unit 1 only)

The applicant stated that the stress models for both units are identical for the RHR/accumulator nozzle to pipe weld, normal and alternate charging line nozzles to pipe weld, and the safety injection BIT nozzle to pipe weld locations. The applicant also stated that the auxiliary feedwater nozzle transition piece is only applicable to Unit 1, since this component does not exist in Unit 2. Furthermore, for the Unit 1 auxiliary feedwater nozzle transition piece, the

WESTEMS™ model has not yet been developed, and when it is developed, it will use a monitoring model consistent with the stress model employed in the governing fatigue analysis of record. Additional information about the component stress models are documented below under the staff's review of RAI 4.3-07, Bullet #5.

The applicant further stated that there is a slight difference between the two units in the stress models for the pressurizer surge line nozzle safe end to pipe weld location. The Unit 1 surge line is 14-inch schedule 140 piping and has a SA-182 F316 safe end, while the Unit 2 surge line is 14-inch schedule 160 piping and has a SA-182 F316L safe end. The applicant stated that, for the surge line hot leg nozzle to pipe weld location, there is a small difference in the stress models due to the difference in the hot leg nozzle geometry at the surge line connection due to the difference in piping schedules between the Units 1 and 2 surge lines.

The staff noted this slight difference in geometry and piping schedule and determined that these differences are not significant with respect to the demonstrations requested in the benchmark evaluations. Therefore, the staff found it acceptable that the applicant used the Unit 2 components (pressurizer surge nozzle safe end to pipe weld and safety injection BIT nozzle coupling to cold leg weld) as the bounding components for the benchmarking evaluations because the 60-year EAF-adjusted CUF (CUF_{en}) values for the Unit 2 components were higher than the Unit 1 components.

Based on its review, the staff finds the applicant's response to RAI 4.3-07 Bullet #1 acceptable because the applicant clarified the usage of WESTEMS™ in its EAF calculations, identified the locations that will be monitored by WESTEMS™, and justified the stress models used at each unit and for any differences between the stress models, as described above. The staff's concerns described in RAI 4.3-07 Bullet #1 are resolved.

<u>RAI 4.3-07, Bullet #2 (including Audit Questions No. 1 to No. 6) and "WESTEMS™ Benchmarking Evaluation - Bullets #1 and #2"</u>

In its response dated December 21, 2010, the applicant addressed RAI 4.3-07, Bullet #2 by stating that the issues identified in the NRC letters dated August 13, 2010 (ADAMS Accession No. ML102300072), and August 20, 2010 (ADAMS Accession No. ML102350440), from the NRC Office of New Reactors are not applicable to any of its monitored WESTEMS™ locations.

The applicant stated that the letter dated August 13, 2010, has two open items, OISRP3.9.1-EMB-05 R3 and OI-SRP3.9.1-EMB-06 R2, and both of these items pertain to the WESTEMS™ NB-3600 module. The Salem EAF calculations and the online fatigue usage monitoring at Salem do not use the NB-3600 module. Therefore, the concerns discussed in the two open items in the August 13, 2010, letter are not applicable to the Salem application of WESTEMS™.

During the audit on January 18–19, 2011, and February 8, 2011, the staff confirmed that calculations performed by the Salem WESTEMS™ do not use the NB-3600 module. The staff also confirmed that the WESTEMS™ module that will be used to monitor online fatigue usage at selected locations does not use the NB-3600 module. The applicant committed in Commitment No. 54 that it will not use or implement the NB-3600 option (module) of the WESTEMS™ program in future online fatigue monitoring and design calculations. Therefore, those portions of this RAI are resolved. It should be noted that the applicant originally proposed three commitments, Commitment Nos. 53, 54, and 55, in responses to the staff's concerns addressed during the audit. During the audit, the staff agreed that Commitment 53 was not necessary and it was retracked by the applicant. Commitments Nos. 54 and 55 were then renumbered to Commitments Nos. 53 and 54, respectively. The discussion in this SER, except for a short discussion below on the retracted Commitment 53, refers to the final Commitment Nos. as shown in the Commitment List in Appendix A of this SER.

The applicant stated that the letter dated August 20, 2010, has one open item, OISRP3.9.1-EMB1-07 R3, which pertains to the ability of the user to modify the stress peak and valley times, selected for inclusion in the fatigue calculations during design fatigue evaluations performed by WESTEMS™. The applicant stated that the Salem WESTEMS™ online fatigue monitoring module does not allow the user to modify the stress peak and valley times used in the online fatigue calculations. Therefore, the issue in the August 20, 2010, letter does not apply to the Salem use of WESTEMS™ for online monitoring. However, the applicant stated that the Salem EAF calculations were performed using the WESTEMS™ design module and that module and the associated Salem-specific fatigue calculations did involve user intervention for adjustment to the stress peak and valley times. Specifically, the analyst removed redundant stress peak and valley times from the fatigue analyses. The applicant stated that the removal of these redundant stress peak and valley times: (1) were technically justified, verified, and documented in the supporting engineering calculations associated with the benchmark evaluations; (2) were considered to have an insignificant impact on the final calculated CUF; and (3) would not result in any CUF exceeding the allowable value of 1.0. The staff's review of the documentation for the removal of redundant stress peak and valley times is documented below.

In its response dated December 21, 2010, the applicant addressed RAI 4.3-07, "WESTEMS™ Benchmarking Evaluation - Bullets #1 and #2" by stating it was currently performing a benchmarking evaluation for both the Unit 2 pressurizer surge nozzle and 1.5-inch BIT safety injection nozzle. The applicant stated that a summary of the results from the benchmarking evaluations would be submitted to the NRC by January 7, 2011.

In its response dated January 7, 2011, the applicant provided a summary of its two benchmarking evaluations. The applicant stated that it performed two benchmarking evaluations to confirm that the results of the WESTEMS™ models, including any analyst judgments, are acceptable and comparable to traditional ASME Code Section III fatigue analyses for the two selected monitored locations. The applicant further stated that the input parameters and assumptions used in the traditional ASME Code Section III fatigue analyses (as documented by representative hand calculations) were the same as those used by the WESTEMS™ design models implemented at Salem. This was confirmed by the staff during the audit performed on January 18–19, 2011, and February 8, 2011.

The applicant stated in its January 7, 2011, letter that the benchmarking evaluation for the Unit 2 pressurizer surge nozzle and 1.5-inch BIT safety injection nozzle consisted of the following:

(1) benchmarking of calculated stresses

(2) benchmarking of WESTEMS™ with a traditional ASME Code Section III analysis (representative hand calculation)

(3) benchmarking of additional fatigue pairs with spreadsheet calculations

(4) benchmarking of the WESTEMS™ online monitoring model

The applicant discussed the detailed steps for each portion of the benchmarking of calculated stresses for both of the selected components. The applicant stated that, in order to benchmark the calculated stresses for both components, the nozzle transfer function stress response from the WESTEMS™ module for each component was compared to an equivalent ANSYS™ finite element analysis of the same input loadings. The applicant stated that an arbitrary transient was imposed on each component to induce a severe thermal shock. Furthermore, the time history stress responses of the two WESTEMS™ models, for each component, at each of several analysis section numbers, were compared to the finite element results. The staff noted that an analysis section number (ASN) referred to a specific area or cross section of the component. Based on the comparisons for all cases, the applicant concluded that the WESTEMS™ transfer functions were acceptable to generate stress histories for all transients input to the Salem WESTEMS™ models.

During the audit, the staff reviewed the details of the applicant's benchmarking evaluation with regards to the calculated stresses for the two limiting components. The staff confirmed that the comparison of the time history stress responses of the two WESTEMS™ models adequately duplicated the results of separate finite element analyses and concluded that the WESTEMS™ transfer functions were acceptable to generate stress histories for use in the benchmarking evaluations of the Unit 2 pressurizer surge nozzle and 1.5-inch BIT safety injection nozzle.

The staff noted that, for the Unit 2 pressurizer surge nozzle safe end to pipe weld location, a hand calculation was performed according to the NB-3200 methodology using a traditional approach to calculate the CUF for the controlling fatigue pair that has the largest incremental usage factor and significant alternating stress. The applicant stated that the controlling fatigue transient pair for this component was formed from stress states of a plant heatup transient with a maximum system ΔT (difference between the pressurizer temperature and the RCS temperature) of 160 °C (320 °F) (heatup at 160 °C (320 °F) ΔT) at the corresponding peak and valley times. During the audit, the staff reviewed the applicant's benchmarking evaluations and confirmed that the applicant had selected the controlling transient pair, which provided the largest incremental usage factor and had the largest significant alternating stress. The staff also confirmed in this benchmarking evaluation that the stress states of a plant heatup at 160 °C (320 °F) ΔT formed the controlling fatigue pair for this component. The staff noted that the largest incremental usage factor from the stress states of a plant heatup at 160 °C (320 °F) ΔT was calculated to be 0.0078 by the hand calculation and by WESTEMS™. The staff also reviewed the hand calculations performed by the applicant for this controlling fatigue transient pair and confirmed that they were performed consistent with the methodology defined in NB-3200. The staff noted that the applicant performed the hand calculation for this single controlling fatigue transient pair to demonstrate that it was consistent with the methodology in NB-3200. The staff further noted that in order to calculate the incremental fatigue usage for the remaining fatigue pairs representing at least 75 percent of the total CUF; the applicant used a Microsoft™ Excel spreadsheet to complete the calculations. The staff, therefore, finds the benchmarking CUF calculations for the pressurizer surge nozzle to be acceptable because the applicant demonstrated that the hand calculations were consistent with the methodology in NB-3200. During the audit, the staff found that the results of hand calculations and the WESTEMS™ design module were essentially identical for all fatigue transient pairs that represented at least 75 percent of the total calculated CUF. The staff finds that the differences were negligible and can be attributed to round off uncertainty.

Based on its review and audit, the staff finds that the Salem application of WESTEMS™ provides results that are consistent with a traditional NB-3200 analysis for the Salem Unit 2 pressurizer surge nozzle safe end to pipe weld.

The staff noted that for the Unit 2 safety injection BIT nozzle to cold leg weld, a hand calculation was performed using NB-3200 methodology to calculate the CUF for the controlling fatigue transient pair that has the largest incremental usage factor and significant alternating stress. The applicant stated that the controlling pair for this component was formed from the two stress states of the inadvertent safety injection transient at the corresponding peak and valley times. During the audit, the staff reviewed the applicant's benchmarking evaluations and confirmed that the applicant selected the controlling fatigue transient pair, which provided the largest incremental usage factor and had the largest significant alternating stress. The staff also confirmed in this benchmarking evaluation that the stress states of an inadvertent injection transient formed the controlling fatigue pair for this component. The staff noted that the largest incremental usage factor from the stress states of an inadvertent injection transient was calculated to be 0.1529 by the hand calculation and 0.1527 by WESTEMS™. The staff also reviewed the hand calculation performed by the applicant for this controlling fatigue transient pair and confirmed that it was consistent with the methodology defined in NB-3200. The staff noted that the applicant performed the hand calculation for this single controlling fatigue pair to demonstrate that it was consistent with the methodology in ASME Code Section III NB-3200 and this resultant fatigue usage from the single transient pair produced a CUF of 0.1527, or 89 percent of the 60-year design CUF for this location as reported in LRA Table 4.3.7-2. The applicant stated that the safety injection BIT nozzle to cold leg weld had only a single fatigue transient pair contributing to over 75 percent of the CUF and, therefore, it was not required to generate additional calculations. The staff finds the benchmarking CUF calculations for the BIT nozzle to be acceptable because the applicant demonstrated that the hand calculations were consistent with the methodology in NB-3200 for the fatigue pairs contributing to at least 75 percent of the total CUF, as requested by the staff. The staff finds that the differences were negligible and can be attributed to round off uncertainty.

Based on its review and the audit, the staff finds that the Salem WESTEMS™ application provides results that are consistent with a traditional NB-3200 analysis for the Unit 2 safety injection BIT nozzle to cold leg weld.

In its response dated January 7, 2011, the applicant stated that, as a part of its completion of the benchmarking evaluations for the Unit 2 pressurizer nozzle safe end to pipe weld location and Unit 2 safety injection BIT nozzle to cold leg weld location, a comparison was made between the results of the WESTEMS™ design module and the online module used to monitor CUF for locations in the enhanced Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant further stated that this step demonstrates that the online monitoring model produces conservative estimates of CUF. The staff noted that, for this portion of the benchmarking evaluations, the WESTEMS™ online monitoring module used the same input design transient loadings as those used in the design module. The staff found this evaluation to be acceptable because it provided a consistent basis for comparison between the fatigue usage obtained in the WESTEMS™ design module and the online monitoring module and demonstrated that the WESTEMS™ online monitoring module was conservative compared to the design module. During its audit, the staff noted that, at the controlling location of the Unit 2 pressurizer surge nozzle safe end to pipe weld, the CUF values calculated by the WESTEMS™ NB-3200 design analysis mode and the WESTEMS™ online monitoring mode were 0.1121 and 0.8061, respectively. The staff also noted that at the controlling location of the Unit 2 safety injection BIT nozzle (coupling) to cold leg weld, the CUF values calculated by the WESTEMS™ NB-3200 design analysis mode and the WESTEMS™ online monitoring mode were 0.1717 and 0.7078, respectively. The staff noted the large differences in the calculated CUF between the design mode and online monitoring mode for each of the two benchmark locations and questioned the reasons for these differences.

The applicant explained (both during the audit and in its January 7, 2011, letter) that the major contributing factors to the differences were as follows:

- The stress peaks and valleys in the online monitoring mode are grouped in 1 ksi intervals. Therefore, stresses are rounded up to the next 1 ksi in magnitude, which leads to increased CUF estimates.

- Different types of stresses are assigned an appropriate sign (positive, "+," or negative, "-") for conservative combination by WESTEMS™. A conservative approach is used by the WESTEMS™ online monitoring module that assigns the sign of the controlling principal stress, determined from the six stress components. This approach results in conservative stress intensity ranges. The purpose of this approach is to maintain conservatism while minimizing computational requirements over time for the monitoring system. Due to the conservative stress intensity ranges and any associated elastic-plastic strain correction factors (K_e) resulting from this assumption, a conservative CUF is computed.

- The WESTEMS™ design analysis mode provides the user with controls on the transient pairing and allows user intervention to remove redundant peaks and valleys that may be present as an artifact of the WESTEMS™ calculation process. Such intervention is not allowed in the "online monitoring" mode. Inclusion of redundant peaks and valleys leads to a more conservative CUF in the online monitoring mode.

Based on its audit and review, the staff finds that, for the applicant's use in determining CUF for Salem, the WESTEMS™ online monitoring mode provides conservative estimates of CUF compared to traditional NB-3200 calculations.

<u>Audit Questions</u>

During the first portion of the audit in January 2011, the staff identified five Audit Questions for additional information. The applicant responded to these five Audit Questions in a letter dated January 31, 2011. During the final day of the audit, in February 2011, the staff identified one additional Audit Question. The applicant responded, in a letter dated February 24, 2011, with updated responses to the first five Audit Questions and a response to the one additional Audit Question. These six questions and the applicant's responses are summarized below.

<u>*Audit Question No.1*</u>:

> In order to close-out the Salem WESTEMS audit, for the WESTEMS "Design CUF" module analysis of the BIT and surge nozzles, provide written explanation and justification of any user intervention in the process including the user intervention applied to the peak and valley selection process.

In its response dated January 31, 2011, the applicant stated that Westinghouse revised the Salem benchmark calculations for the Unit 2 pressurizer surge nozzle safe end to pipe weld and the Unit 2 safety injection BIT nozzle coupling to cold leg weld to document and technically justify the user intervention that was applied in the CUF calculations. The revisions to the benchmark evaluations specifically documented the following:

(1) Description of the WESTEMS™ stress peak and valley selection algorithm.

(2) WESTEMS™ results without analyst intervention during the CUF calculation.

(3) Graphical identification of the stress peaks and valleys removed by the analyst.

(4) Technical justification for analyst removal of the stress peaks and valleys on a transient-by-transient basis. Documentation is provided in the new section in the applicant's evaluation justifying removal of redundant stress peaks and valleys for each transient.

(5) For the Unit 2 safety injection BIT nozzle coupling to cold leg weld location, two new tables were added comparing the fatigue pairs and corresponding CUF calculated using analyst intervention to the CUF calculated where no analyst intervention was involved. For the Unit 2 pressurizer surge nozzle safe end to pipe weld location, the CUF calculated using analyst intervention and the CUF calculated where no analyst intervention was involved were identical.

The applicant provided justification for removal of redundant stress peaks and valleys for the Unit 2 safety injection BIT nozzle coupling to cold leg weld location. The applicant clarified that the 60-year design CUF listed in LRA Table 4.3.7-2 reflects justified analyst intervention during the stress peak and valley process. The staff agreed that for these cases, the analyst intervention in removing redundant stress peaks and valleys was justified.

During the final day of the audit, on February 8, 2011, the staff confirmed that the applicant revised its fatigue evaluations for Unit 2 pressurizer surge nozzle safe end to pipe weld location and Unit 2 safety injection BIT nozzle coupling to cold leg weld location to document the staff requests made after the initial 2 days of the audit. In addition, the staff reviewed the graphical comparison of the stress peaks and valleys eliminated by the analyst and the analyst's written technical justification for doing so. The staff noted that there were instances in which stress peaks and valleys were removed by the analyst, added by the analyst, or were not modified by the analyst from the WESTEMS™ program run. The applicant discussed with the staff in detail the justification for removing any stress peaks and valleys from the WESTEMS™ program run. During this review and the associated discussion, the staff noted that the justification for the removal of two stress peaks and valleys from the Unit 2 safety injection BIT nozzle coupling to cold leg weld location fatigue evaluation was not correct and not sufficiently documented in the calculation.

In its response dated February 24, 2011, the applicant provided the detailed basis for the analyst removal of the peak and valley times from the data. The applicant stated that the bases for removing the peak and valley times include:

- One peak was removed because it represented the same total stress as a prior peak and, since the primary plus secondary stress in this evaluation does not result in any K_e (simplified elastic-plastic penalty factor applied to alternating stress when the primary plus secondary stress intensity range limit is exceeded) values greater than 1.0, it is redundant with the previous peak and not required.

- Two of the peaks in the transient are redundant peaks of the initial state captured by a peak time, since the transient returns to the same stress state as it started, and this stress state is redundant to another transient that begins at a similar plant no-load condition.

The applicant also stated that the analyst added one peak that was not selected by WESTEMS™ at the initial time of the transient for additional conservatism in the fatigue evaluation. The staff found that the addition of any stress peaks and valleys is acceptable because this practice will yield a more conservative CUF value. The applicant stated that the BIT nozzle calculation has been updated to properly capture the basis for the user intervention activity.

With the submittal of the information by a letter dated February 24, 2011, the staff verified that the applicant has adequate documentation and written technical justification for removal of stress peaks and valleys by the analyst in determination of the CUF for the two locations investigated in the benchmark evaluations.

The staff noted that 10 CFR 54.37(a) states that all information and documentation required by, or otherwise necessary, to document compliance with the provisions of 10 CFR Part 54 shall be retained in an auditable and retrievable form for the term of the renewed operating license or renewed combined license by the licensee. The staff further noted that these benchmarking evaluations and revised EAF analyses, which are to include the written explanation and technical justification of any user intervention applied for any WESTEMS™ “Design CUF” (NB-3200) module analyses, support the applicant’s disposition of this TLAA, in accordance with 10 CFR 54.21(c)(1)(iii).

Based on its review, the staff finds the applicant’s response to Audit Question No. 1, as amended by letter dated February 24, 2011, acceptable because, in accordance with 10 CFR 54.37(a), the applicant provided justification and documentation for any user intervention applied to any WESTEMS™ “Design CUF” (NB-3200) module analyses. This supports the applicant’s disposition in accordance with 10 CFR 54.21(c)(1)(iii) for these monitored locations. Audit Question No. 1 is resolved.

Audit Question No. 2:

> For any WESTEMS “Design CUF” module analyses performed for the remaining monitored locations at Salem (i.e., other than the BIT and surge nozzles), provide written explanation and justification of any user intervention applied in the process including the user intervention applied to the peak and valley selection process prior to two years before entering the period of extended operation.

In its response dated January 31, 2011, the applicant proposed Commitment No. 53[2] to revise the fatigue calculations for all locations monitored at Units 1 and 2 to include written explanation and technical justification of any user intervention applied for any WESTEMS™ “Design CUF” module analyses at least 2 years prior to the period of extended operation. In its response dated February 24, 2011, the applicant revised the response to Audit Question No. 2 and retracted the proposed Commitment No. 53. The applicant stated that, after discussions with the vendor who performed the fatigue calculations, the stress peak and valley editing during the fatigue calculation process for the remaining locations monitored by WESTEMS™ at Units 1 and 2 is consistent with that used for the two locations that were the subject of the WESTEMS™ benchmarking audit. Therefore, the applicant stated that it is unnecessary to revise existing EAF calculations performed for the remaining WESTEMS™ monitored locations to include a

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[2] This was the Commitment noted above that was later retracted. The former Commitment No. 54 was renumbered Commitment 53.

written explanation and justification of any user intervention applied for any WESTEMS™ “Design CUF” (NB-3200) module analyses.

Based on its review, the staff finds the applicant’s response to Audit Question No. 2, as amended by letter dated February 24, 2011, and removal of proposed Commitment No. 53 (January 31, 2011), acceptable because the staff has re-considered the need for proposed Commitment No. 53 and found that the audit results and documentation provided during the February audit provide reasonable assurance of the applicant’s acceptable methods and ability to document the user interaction in deleting and adding stress peaks and valleys, and thus implementation of proposed Commitment No. 53 is not necessary. However, in order to comply with the requirements of 10 CFR 54.37(a), the staff expects that the applicant would be able to show, through its documentation and references, where user intervention was needed for use of WESTEMS™ “Design CUF” (NB-3200) module analyses. Audit Question No. 2 is resolved.

Audit Question No. 3:

> For any use of the WESTEMS “Design CUF” module in the future at Salem, include written explanation and justification of any user intervention in the process.

In its response dated January 31, 2011, and subsequently updated in the letter dated February 24, 2011, the applicant provided Commitment No. 53 (initially identified as proposed Commitment No. 54 in the January 31, 2011, response) to include written explanation and justification of any user intervention in future evaluations using the WESTEMS™ “Design CUF” (NB-3200) module. The commitment will be implemented within 60 days of issuance of the renewed operating license. The staff noted that Units 1 and 2 will enter the period of extended operation in August 2016 and April 2020, respectively. The staff finds the applicant’s accelerated implementation schedule reasonable because the applicant is aggressively ensuring that a written explanation and justification of any user intervention in future evaluations using the WESTEMS™ “Design CUF” (NB-3200) module is documented and provides the applicant sufficient time to document and implement necessary procedures.

The staff noted that 10 CFR 54.37(a) states that all information and documentation required by, or otherwise necessary, to document compliance with the provisions of 10 CFR Part 54 shall be retained in an auditable and retrievable form for the term of the renewed operating license or renewed combined license by the licensee. The staff further noted that these revised EAF evaluations, which are to include the written explanation and technical justification of any user intervention applied for any WESTEMS™ “Design CUF” module analyses, support the applicant’s disposition of this TLAA, in accordance with 10 CFR 54.21(c)(1)(iii).

Based on its review, the staff finds the applicant’s response to Audit Question No. 3 and Commitment No. 53 acceptable because the applicant will document, with a written explanation and technical justification, any user intervention associated with future evaluations using the WESTEMS™ “Design CUF” (NB-3200) module to ensure that the basis for the conclusions in these evaluations are auditable and retrievable. Audit Question No. 3 is resolved.

Audit Question No. 4:

> Provide a commitment that the NB-3600 option of the WESTEMS “Design CUF” module will not be implemented or used in the future at Salem.

In its response dated January 31, 2011, and subsequently updated in a letter dated February 24, 2011, the applicant provided Commitment No. 54 (initially identified as proposed Commitment No. 55 in the January 31, 2011, response) not to use or implement the NB-3600 module of the WESTEMS™ program in future online monitoring and design CUF calculations. The commitment will be implemented within 60 days of issuance of the renewed operating license. The staff finds the applicant's accelerated implementation schedule reasonable because the applicant is ensuring that the NB-3600 module of the WESTEMS™ program is not used for online monitoring and design calculations and provides the applicant sufficient time to document and implement necessary procedures to prevent the use of the NB-3600 module.

Based on its review, the staff finds the applicant's response to Audit Question No. 4 acceptable because: (1) one of the open items identified in the staff's letter dated August 13, 2010, is not applicable to the applicant, (2) the staff confirmed that the applicant's EAF calculations used only the NB-3200 module of the WESTEMS™ program, and (3) the applicant committed (Commitment No. 54) not to use or implement the NB-3600 module of the WESTEMS™ program in future online monitoring and design CUF calculations. Audit Question No. 4 is resolved.

Audit Question No. 5:

> Provide a description of the peak and valley selection process used by WESTEMS and how that process aligns with ASME Code NB-3216 methodology.

In its response dated January 31, 2011, the applicant stated that the WESTEMS™ algorithm selects stress peaks and valleys consistent with the criteria in ASME Code Section III, NB-3216. The applicant stated that performing a fatigue evaluation in accordance with ASME Code Section III, subparagraph NB-3200 requires calculating the stress differences for each type of stress cycle in accordance with NB-3216. The staff noted that, as delineated in NB-3216.2(b), the analyst is required to choose a point in time when the stress components are one of the extremes for the cycle (either maximum or minimum algebraically). The applicant stated that WESTEMS™ fatigue evaluations employ a stress-intensity-based approach to "choose a point in time" as follows:

> For each transient cycle in the component fatigue evaluation, the six stress components of Primary plus Secondary stress and of Total stress are calculated for the entire transient time history. Then, the stress intensities for the Primary plus Secondary stress and the Total stress time histories are calculated. Relative maxima and minima within the Primary plus Secondary stress and Total stress intensity time histories for each transient are identified using the second derivative test (comparing the slopes of the stress history around a time point).

The applicant stated that this stress-intensity-based approach identifies the time points of these extremes. From those extremes, the stress component ranges, the principal stress ranges, and the resulting stress intensity ranges are calculated between two selected stress states using the corresponding component stress at those time points. The applicant also stated that when using the stress-intensity-based approach, the time points where stress conditions are extreme are picked at the relative stress peak and valleys, or at the maximum or minimum stress states along the stress intensity time history. The applicant stated the stress-intensity-based approach is consistent with the procedure used in NB-3216.2 and employs similar practices to those used by analysts over many decades of applying NB-3200 requirements.

Based on its review, the staff finds the applicant's response to Audit Question No. 5 acceptable because the stress-intensity-based approach is a practical method to interpret and apply ASME Code Section III, NB-3216.2 methodology regarding the selection of extremes for cyclic loading. Audit Question No. 5 is resolved.

The staff's request in Audit Question No. 6 and the applicant's response are discussed in RAI 4.3-07, Bullet #5.

Based on a 3-day audit, the staff found the Salem CUF calculations, and the applicant's use of WESTEMS™ to perform NB-3200 fatigue evaluations, addresses the staff's concerns and provide assurance that the WESTEMS™ "Design-CUF" (NB-3200) fatigue evaluation provides a consistent analysis with the ASME Code Section III, NB-3200 analysis of the Salem WESTEMS™ application. The staff concludes the following:

- There is reasonable assurance that Salem's use of the WESTEMS™ "Design-CUF" (NB-3200) module provides calculations of CUFs that are consistent with traditional ASME Code Section III analyses.

- There is reasonable assurance that the ability of program users to delete or add stress peak and valley times has been properly justified and documented.

- The WESTEMS™ NB-3600 module is not currently used in the Salem application of WESTEMS™ and any future use of the NB-3600 module requires staff review and approval prior to use.

Based on its review, the staff finds the applicant's response to RAI 4.3-07, Bullet #2 acceptable because, based on the 3-day audit and the applicant's responses associated with the Audit Questions, the staff found that the applicant's CUF calculations and its use of WESTEMS™ to perform NB-3200 fatigue evaluation address staff concerns regarding the user intervention process and the use of the NB-3600 module. Therefore, the staff's concern described in RAI 4.3-07, Bullet #2 is resolved.

RAI 4.3-07, Bullet #3

In its response dated December 21, 2010, the applicant provided a summary table of the history of fatigue analyses prepared for each of the locations monitored by WESTEMS™ at Salem. In the RAI response, the applicant also provided a detailed description of the information contained in this summary table.

The applicant stated that for all of the monitored component locations, with the exception of the Unit 1 auxiliary feedwater nozzle transition piece that is not part of the RCPB, the EAF evaluations were performed to address the GALL Report recommendations to evaluate the effects of the reactor water environment on fatigue. The applicant stated that it used NUREG/CR-6583 and NUREG/CR-5704 to account for EAF by increasing the fatigue usage factor by an appropriate F_{en} factor. The applicant stated these NUREG reports do not require a complete ASME Code Section III qualification of the components, but only a CUF calculation.

The applicant clarified that only the pressurizer surge nozzle safe end to pipe weld and the surge line hot leg nozzle to pipe weld had an existing ASME Code Section III fatigue evaluation, which were updated to ASME Code Section III from the original American Standards

Association/United States of America Standards (ASA/USAS) B31.1 design code in Westinghouse Commercial Atomic Power Vendor Report (WCAP)-12914 to address NRC Bulletin 88-11 concerns. The applicant stated that a design specification was not prepared for the updated evaluation because the original design was the ASA/USAS B31.1 Power Piping Code. The staff noted that the stratification effects postulated for the standard Westinghouse plant transient conditions, as described in WCAP-12914, were included in the plant-specific benchmark evaluation for this component.

The applicant also explained that the pressurizer surge nozzle safe end to pipe weld location was also re-evaluated in 2003 in WCAP-16194. This analysis was a plant-specific evaluation of insurge/outsurge transients previously defined by the Westinghouse Owners' Group (WOG) in WCAP-14950, "Mitigation and Evaluation of Pressurizer Insurge/Outsurge Transients," February 1998. These transients were not considered in the original design analysis for the pressurizer surge nozzle and piping. This analysis was performed using the 1989 Edition of the ASME Code. Furthermore, the relevant design specifications were not updated to include these additional details. Although the insurge/outsurge transients and stratification effects postulated during the design specification transients are described in WCAP-16194, the staff noted that WCAP-16194 did not provide a formal ASME Code Section III reconciliation between the 1986 and 1989 ASME Code editions. The applicant stated that the latest evaluations for the surge line and nozzle locations are documented in WCAP-16994-P and WCAP-16995-P for Salem Units 1 and 2, respectively, and that these evaluations used the same ASME Code edition (1986) as was used in WCAP-12914. The applicant further stated that the evaluations documented in WCAP-16994-P and WCAP-16995-P for Salem Units 1 and 2, respectively, are considered to be the latest governing analyses of record.

The staff noted that the RHR accumulator nozzle to pipe weld, normal and alternate charging nozzle to pipe weld, and BIT nozzle at socket weld components were originally designed to the ASA/USAS B31.1 Power Piping Code and, therefore, there was no design specification to cover fatigue analysis for these components because ASA/USAS B31.1 does not require explicit fatigue analysis. The staff also noted that the EAF evaluations documented in WCAP-16994-P and WCAP-16995-P only performed a CUF calculation; therefore, a full ASME Code Section III qualification was not performed. The applicant stated that the ASME Code Section III CUF values documented in WCAP-16994-P and WCAP-16995-P were calculated using transients from Westinghouse systems standard specifications applicable to Westinghouse 4-loop plants. The transients, ASME Code methodology, and criteria used for the evaluations were documented in WCAP-16994-P and WCAP-16995-P and their supporting calculations.

Since the original design for the Salem piping components were based on ASA/USAS B31.1 Power Piping Code requirements, the staff agrees that a formal code reconciliation was not necessary to address the recommendations of GALL AMP X.M1 to consider the effects of reactor water environment because only a CUF calculation was needed.

Based on its review, the staff finds the applicant's response to RAI 4.3-07, Bullet #3 acceptable because for each monitored location, the applicant: (1) clarified the associated historical fatigue analyses, (2) justified not performing a formal code reconciliation, and (3) performed its CUF calculations consistent with the methodology in ASME Code Section III. Therefore, the staff's concern described in RAI 4.3-07, Bullet #3 is resolved.

RAI 4.3-07, Bullet #4

In its response dated December 21, 2010, the applicant stated that each location monitored by WESTEMS™ was evaluated for EAF, except for the Unit 1 auxiliary feedwater nozzle transition piece, which is not a Class 1 component. The applicant further stated that the EAF analyses for each monitored location consisted of the following general steps:

(1) prepare transfer function databases, including thermal transfer function and mechanical transfer function models, using the ANSYS™ Finite Element Code

(2) create WESTEMS™ models for the Salem-specific component locations

(3) define input design-basis thermal transients for each monitored location and create transient input files

(4) perform applicable stress and fatigue calculations for limiting component locations using the stress and fatigue analysis methods of ASME Code Section III, NB-3200 to determine the 60-year CUF using the transfer function models in WESTEMS™

(5) evaluate the reactor coolant environmental effects as an environmental multiplier (F_{en}) and apply this multiplier to the 60-year CUF

During the audit on January 18–19, 2011, and February 8, 2011, the staff reviewed the applicant's methodology used to perform the Salem benchmark evaluations. The staff confirmed that the applicant used the design-basis transients as inputs into the WESTEMS™ design analysis module to calculate CUF. The staff's review of the applicant's methodology used to determine F_{en} values is documented in SER Section 4.3.7.2.

Based on its review, the staff finds the applicant's response to RAI 4.3-07, Bullet #4 acceptable because: (1) the applicant clarified the general steps in the EAF analyses and (2) the Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors the transients to ensure that the CUF considering environmental effects remains below the design limit of 1.0. Therefore, the staff's concern described in RAI 4.3-07, Bullet #4 is resolved.

RAI 4.3-07, Bullet #5

In its response dated December 21, 2010, the applicant stated that the current governing fatigue analysis for each of the locations monitored by WESTEMS™, with the exception of the Unit 1 auxiliary feedwater nozzle transition piece, is the recent EAF analysis described in WCAP-16994-P and WCAP-16995-P for Units 1 and 2, respectively. Furthermore, the ASME Code Section III CUF values were calculated for each location using transients from Westinghouse systems standard specifications applicable for Westinghouse 4-loop plants. The staff concluded that these EAF analyses consist of an analysis performed consistent with the methodology of NB-3200 and also incorporate up-to-date transients and associated loadings.

The applicant stated that the stress models used in these EAF analyses are the same as the stress models employed in the Salem WESTEMS™ online monitoring module. The applicant also stated that, for the future application of the WESTEMS™ online monitoring for the Unit 1 auxiliary feedwater nozzle transition piece, the model will use a monitoring model consistent with the stress model employed in the governing fatigue analysis of record.

However, based on the discussions during the February 8, 2011, audit, the staff identified that, for the Salem pressurizer surge nozzle safe end to pipe weld location, a different version of the WESTEMS™ stress model was used for the fatigue analysis than the model that will be used for online fatigue monitoring. The staff requested, in Audit Question No. 6, the applicant to clarify the contradiction. In its response dated February 24, 2011, the applicant amended the response to RAI 4.3-07, Bullet #5 indicating that the pressurizer surge nozzle safe end to pipe weld location and the surge line hot leg nozzle to pipe weld location are the two monitored locations that have a different stress model between the EAF analysis and the online monitoring. The applicant stated that the stress models for these two locations in the EAF analysis are specific to each Salem unit due to the slight physical differences in the pipe wall thickness of the 14-inch surge line. The staff noted that the difference in the pipe wall thickness is documented in its evaluation of the applicant's response to RAI 4.3-07, Bullet #1. The applicant stated that the stress model to be used in the online monitoring will be common to both units, and the applicant determined that this approach will be conservative and bounding for these two locations. The applicant confirmed that the same stress models were used for the EAF analysis and online monitoring for all other locations to be monitored by WESTEMS™.

The staff noted that a meaningful comparison can be made between the calculated CUF from design transients and the actual CUF calculated from actual plant transients because each location monitored by WESTEMS™, with the exception of the Unit 1 auxiliary feedwater nozzle transition piece, used the same stress models in the EAF analysis and the WESTEMS™ online monitoring tool. This CUF comparison is useful and informative because it can be used to determine if a design fatigue analysis remains valid.

Based on its review, the staff finds the applicant's response to RAI 4.3-07, Bullet #5 and Audit Question No. 6 acceptable because: (1) the applicant clarified whether the stress model used in the online monitoring and that used in the EAF analyses are the same or not; (2) for the two monitored locations at the pressurizer surge lines, justification is provided that a common and conservative model will be used for both units due to the slight physical difference; and (3) the applicant has used (or will use) the same stress models for the monitoring tool and the governing fatigue analysis of record for all remaining four locations monitored by WESTEMS™, such that meaningful comparison between the calculated CUF and the CUF calculated from actual transients can be used to determine if a design fatigue analysis remains valid and if the design limit of 1.0 will be exceeded. The staff's concern described in RAI 4.3-07, Bullet #5 is resolved.

RAI 4.3-07, Bullet #6

In its response dated December 21, 2010, the applicant stated that the transient counting results (i.e., current number of cycles) were used as a basis for the 60-year projected cycles. In addition, the applicant stated that the current cycles, the 60-year projected cycles, and the NSSS (40-year) design limit for each of the design transients are listed in LRA Tables 4.3.1-3 and 4.3.1-4. The applicant also stated that either the 60-year projected cycles, or the bounding NSSS (40-year) design limit values were used as inputs into the ASME Code Section III 60-year CUF calculations documented in WCAP-16994-P and WCAP-16995-P for Units 1 and 2, respectively. The staff noted that the results of the calculations are listed in the column entitled, "60-Year Design CUF," in LRA Tables 4.3.7-1 and 4.3.7-2. Furthermore, the 60-year design CUF values were multiplied by the corresponding fatigue life correction factor, F_{en}, to obtain the 60-year CUF_{EAF} values listed in LRA Tables 4.3.7-1 and 4.3.7-2 for Salem Units 1 and 2, respectively.

The staff noted that those locations identified by the applicant as plant-specific components corresponding to the NUREG/CR-6260 locations and the associated TLAAs were dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), as amended by letter dated July 13, 2010, stating that the effects of the reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation. The staff also noted that the applicant committed (via Commitment No. 52) by letter dated December 21, 2010, as part of its Metal Fatigue of Reactor Coolant Pressure Boundary Program, to ensure that the most limiting plant-specific locations are evaluated for effects of reactor coolant environment. The staff's review of the applicant's disposition and Commitment No. 52 is documented in SER Section 4.3.7.2.

Based on its review, the staff finds the applicant's response to RAI 4.3-07, Bullet #6 acceptable because the applicant's Metal Fatigue of Reactor Coolant Boundary Program monitors fatigue usage to ensure that the CUF, including environmental effects, remains below the design limit of 1.0. Furthermore, the applicant committed (Commitment No. 52) to ensure that the effects of reactor water environment on fatigue life will be considered for the most limiting plant-specific locations, and the applicant clarified how the transient cycles are incorporated into the EAF analyses. The staff's concern described in RAI 4.3-07, Bullet #6 is resolved, and Open Item OI 4.3.4.2-1 is closed.

The staff also reviewed the portions of the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.3.1.1 states an enhancement to the "parameters monitored or inspected" program element. This enhancement expands the existing program to include additional transients beyond those defined in the TSs and the UFSAR, and also expands the program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring. The applicant committed to implement this enhancement prior to the period of extended operation, as identified in Commitment No. 47, LRA Appendix A, Section A.5.

The staff reviewed this enhancement against the corresponding program element in GALL AMP X.M1. During its review, it was not evident to the staff whether the stated enhancement was being made to make the "parameters monitored or inspected" program element consistent with the corresponding element in GALL AMP X.M1. It was also not clear to the staff what was being enhanced relative to the information that was already provided for the Metal Fatigue of Reactor Coolant Pressure Boundary Program and whether the enhancement will be on the basis document or the implementing procedure, or both.

By letter dated June 30, 2010, the staff issued RAI B.3.1.1-1, Request 1, requesting that the applicant confirm if the stated enhancement is being proposed to make the "parameters monitored or inspected" program element consistent with GALL AMP X.M1. The staff also asked the applicant to clarify whether the enhancement will be of the basis document or the implementing procedure for this program, or both.

In its response dated July 28, 2010, the applicant clarified that the purpose of the stated enhancement was to make the "parameters monitored or inspected" program element consistent with the corresponding program element in GALL AMP X.M1 because the GALL

Report recommends the monitoring of all plant transients that cause cyclic strains, which are significant contributors to cumulative fatigue usage. The applicant clarified that the enhancement was necessary because additional transients were identified that would need to be tracked by the program, beyond those in the current program. The applicant also clarified that the enhancement will be implemented by issuing new implementing procedures and revising current program implementing procedures to include monitoring of the additional transients added by Enhancement 1.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, Request 1, acceptable because: (1) Enhancement 1 will make the program element consistent with that in the "parameters monitored or inspected" program element in GALL AMP X.M1, and (2) the applicant has appropriately reflected this enhancement in Commitment No. 47 and will implement the enhancement prior to entering the period of extended operation, as recommended in SRP-LR Section 3.0. The staff's concern described in RAI B.3.1.1-1, Request 1 is resolved.

During its review, the staff identified that the transients specified in the TS Table 5.7-1 are required to be tracked pursuant to the requirements in TS 5.7.1. The staff also identified that the design-basis transients are located in the UFSAR and includes transients listed in TS Table 5.7-1 and transients that are outside of the TS requirements. It was not evident to the staff which process would be taken to track those design-basis transients that are in the UFSAR but that are outside TS 5.7.1.

By letter dated June 30, 2010, the staff issued RAI B.3.1.1-1, Request 2, requesting that the applicant clarify the process, procedure, or protocol that will be used to track the occurrences of those design-basis transients that are listed in the UFSAR but are not within TS 5.7.1.

In its response dated July 28, 2010, the applicant clarified that the design-basis transients are discussed in UFSAR Section 5.2.1.5 and are listed in UFSAR Tables 5.2-10 and 5.2-10a. The applicant also clarified that the implementation of appropriate station procedures will be used to track the occurrences of those design-basis transients in the UFSAR that are outside of TS 5.7.1. The applicant clarified that the existing plant procedures currently track transients listed in the TSs but that, under Enhancement 1, the procedures will be enhanced to ensure that those design-basis transients that are outside of TS 5.7.1 will be tracked for the period of extended operation. The applicant stated that the enhanced procedures will be credited for implementation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated that the implementing procedures will be annotated to identify the associated license renewal program commitments.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, Request 2, acceptable because the applicant: (1) clarified that its plant procedures will ensure that those UFSAR design-basis transients outside of TS 5.7.1 will be tracked by the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program and (2) is monitoring all plant transients that cause cyclic strains, which are significant contributors to cumulative fatigue usage, as recommended by the GALL Report. The staff's concern described in RAI B.3.1.1-1, Request 2 is resolved.

The staff also noted that the applicant identified additional transients that would need to be added to the scope of the program and to the appropriate implementing procedures. However, the applicant did not identify which transients would need to be added to the scope of the Metal Fatigue of Reactor Coolant Pressure Boundary Program. Thus, it was not evident to the staff which transients were being referred to in the Enhancement 1 or whether it is necessary to track these additional transients for possible inclusion in updated CUF analyses. It was also not evident to the staff whether the applicant would be updating the design-basis transients in the UFSAR to include these additional transients.

By letter dated June 30, 2010, the staff issued RAI B.3.1.1-1, Request 3, requesting that the applicant identify the additional transients that were being referred to in Enhancement 1 and clarify which ASME Code Class 1 components these additional transients are related to. The staff also asked the applicant to clarify whether an update of the design basis will be performed to include these transients and if so, identify which of the sections or tables of the UFSAR will be updated. The staff also requested that the applicant clarify whether this would be covered within the applicable LRA commitment. The staff also asked the applicant to justify its basis for omitting these transients from the design basis if the design basis will not be updated to include these transients.

In its response dated July 28, 2010, the applicant clarified that the only additional transient referred to in Enhancement 1 that is related to a Class 1 component is the "Inadvertent Auxiliary Spray to Pressurizer" transient. The applicant stated that the design-basis transient is related to the pressurizers in the RCPB and their associated surge nozzles. The applicant stated that the transient is within the scope of the current TSs or UFSAR. The applicant clarified, however, that this transient is manually counted by the current program. The applicant clarified that this transient is included in the design basis due to its inclusion in the current program and thus, no changes to the design-basis transient discussions in the UFSAR sections are required or are being anticipated as a result of the inclusion of this transient.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, Request 3 acceptable because: (1) the applicant identified that the "Inadvertent Auxiliary Spray to Pressurizer" transient is the only additional design-basis transient that was not accounted for in the implementing procedures, (2) the applicant clarified that the transient is already accounted for in the design basis, and (3) implementation of the enhancement will correct the omission of this transient in the implementing procedure prior to entering the period of extended operation. The staff's concern described in RAI B.3.1.1-1, Request 3 is resolved.

During the staff's review, it was identified that the program will be enhanced to expand the "fatigue monitoring program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring." However, the staff noted that Enhancement 4 is similar to Enhancement 1, which affects the "corrective actions" program element. The "corrective actions" program element of GALL AMP X.M1 states, in part, that for programs that monitor a sample of high fatigue usage locations, "corrective actions include a review of additional affected reactor coolant pressure boundary locations." The staff noted that this program element in GALL AMP X.M1 specifically discusses expansion of programs to additional RCPB components. Thus, it is not apparent to the staff whether the expansion criteria in Enhancement 1 is applicable to the "scope of the program," "monitoring and trending," or "corrective actions" program elements or whether it is redundant with the enhancement discussed in Enhancement 4.

By letter dated June 30, 2010, the staff issued RAI B.3.1.1-1, Request 4, requesting that the applicant clarify whether the expansion criterion in Enhancement 1 is applicable to the "monitoring and trending" or "corrective actions" program element, or whether it is redundant with Enhancement 4. The staff also asked the applicant to justify why the expansion of the transients and components aspect of Enhancement 1 is not applicable to the "scope of the program" or "monitoring and trending" program elements and if the expansion of the transients and components aspect does not relate to a corrective action activity.

In its response dated July 28, 2010, the applicant clarified that the expansion criterion in Enhancement 1 is for the expansion of the number of transients and components being monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant also stated that it does not pertain to the expansion of American National Standards Institute (ANSI) B31.1 RCPB piping locations into the scope of the program as a result of being scoped into the EAF analysis. As a result, the applicant clarified that the expansion criterion in Enhancement 1 was not redundant with Enhancement 4, which does pertain to the EAF analysis. The applicant also clarified that, although Enhancement 1 does not provide enhancements to the "scope of the program" or the "corrective actions" program elements, a supplemental review of Enhancement 1 determined that the enhancement is applicable to the "monitoring and trending" program element because: (1) the "monitoring and trending" program element in GALL AMP X.M1 recommends that the program monitor a sample of high fatigue usage locations and that the sample be augmented to include, as a minimum, the locations identified in NUREG/CR-6260 or alternative locations based on the plant's configuration; (2) the applicant determined that additional transients and a sample of high fatigue usage locations met the GALL Report recommendation; and (3) the implementation of Enhancement 1 will account for the need to add these transients and component locations to the scope of the program, as addressed in the "parameters monitored and inspected" and "monitoring and trending" program elements.

The staff also noted that by letter dated July 28, 2010, the applicant amended Enhancement 1 to be applicable to the "parameters monitored or inspected" and "monitoring and trending" program elements. Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, Request 4 acceptable because: (1) the applicant amended Enhancement 1 to include both the "parameters monitored or inspected" and "monitoring and trending" program elements, (2) implementation of the applicant's amended enhancement will ensure the inclusion of the additional component locations and transients into the implementing procedures, and (3) the implementation of the program during the period of extended operation will be consistent with the "parameters monitored or inspected" and "monitoring and trending" program element recommendations in GALL AMP X.M1. The staff's concern described in RAI B.3.1.1-1, Request 4 is resolved.

Based on its review, the staff finds Enhancement 1, when implemented prior to the period of extended operation, acceptable because it is consistent with the recommendations of GALL AMP X.M1 as described above.

Enhancement 2. LRA Section B.3.1.1 states an enhancement to the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. The staff noted that this enhancement expands the existing program to use a software program to automatically count transients and calculate cumulative usage on select components. The applicant committed to implement this enhancement prior to the period of extended operation, as identified in Commitment No. 47, LRA Appendix A, Section A.5.

The staff noted that this software program does not use the Green's functions analysis methodology, as discussed in NRC RIS 2008-30, and is based on methods defined in ASME Code Section III, NB-3200. The staff noted that the applicant's enhancement incorporates use of a software program to automatically count transients and calculate cumulative usage on select components as a preventive measure to mitigate fatigue cracking of metal components of the RCPB, which is an acceptable approach and is consistent with the recommendation in GALL AMP X.M1.

During the staff's review, it was not evident whether Enhancement 2 is being made to make the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements consistent with the corresponding program elements in GALL AMP X.M1. It was also not apparent to the staff exactly what is being enhanced and specifically whether it will involve an enhancement of the computer programming for the monitoring software, the basis document, or the implementing procedure. It is also not evident to the staff how this enhancement will be tied to program elements and to the implementing procedure for the software package if the enhancement only pertains to an update of WESTEMS™ to cover the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements in GALL AMP X.M1.

By letter dated June 30, 2010, the staff issued RAI B.3.1.1-2 requesting that the applicant confirm that Enhancement 2 is being proposed to make the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements consistent with GALL AMP X.M1. The staff also asked the applicant to clarify what will be enhanced. In addition, the staff asked the applicant to justify why the associated program elements and implementing procedure would not have to be updated to account for Enhancement 2, if the implementation of the enhancement will be limited only to an anticipated update of WESTEMS™.

In its response dated July 28, 2010, the applicant clarified that Enhancement 2 will make the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements consistent with GALL AMP X.M1 and that each of these elements has attributes which will be enhanced with the expansion to the existing software program. The applicant clarified that the current Metal Fatigue of Reactor Coolant Pressure Boundary Program uses a fatigue monitoring software program for monitoring of the CUF values associated with the pressurizer lower head and surge nozzle. The applicant clarified that Enhancement 2 will expand the current fatigue monitoring program to apply and implement the use of the fatigue monitoring software program to monitor the CUF values for additional selected component locations, including the remainder of EAF locations, that correspond to those recommended in NUREG/CR-6260 and that the enhancement is not only limited to a potential update of WESTEMS™. The applicant further clarified that the enhancement for implementation of WESTEMS™ will include not only installation of the fatigue monitoring software program to include monitoring for additional locations and potential CUF updates of the locations, but also call for the establishment of new procedures and revision of existing procedures and for the implementation of these procedures to account for WESTEMS™.

The staff noted that the implementation of the WESTEMS™ fatigue software involves including additional locations that are not currently being monitored by the software program. The staff also noted the enhancement to apply WESTEMS™ for cycle counting and potentially for CUF updates of the component locations and also includes updating the implementing procedures to incorporate the applications of WESTEMS™. The staff also noted that the corresponding "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements in GALL AMP X.M1 incorporate key component location selection, cycle monitoring, CUF update, and development of appropriate acceptance criteria elements that would need to be enveloped by the software programming in order to validate WESTEMS™.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-2 and Enhancement 2 acceptable because: (1) the applicant is applying the enhancement for the software program to the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements to ensure that the implementation of the software program will be consistent with the corresponding program elements in GALL AMP X.M1; (2) the enhancement includes the need to incorporate the use of the software program into the implementing procedures; and (3) the applicant has included the need for this enhancement in Commitment No. 47 to implement the enhancement prior to entering the period of extended operation. The staff's concern described in RAI B.3.1.1-2 is resolved.

Enhancement 3. LRA Section B.3.1.1 states an enhancement to the "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. The staff noted that this enhancement expands on the existing program to address the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant identified in NUREG/CR-6260. The applicant committed to implement this enhancement prior to the period of extended operation, as identified in Commitment No. 47, LRA Appendix A, Section A.5.

The staff reviewed this enhancement against the corresponding program elements in GALL AMP X.M1. The staff noted that the applicant's Enhancement 3 appropriately expands the existing program to address the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant identified in NUREG/CR-6260, as required by GALL AMP X.M1. However, it was not evident to the staff whether this enhancement was being used to make the "preventive actions," "parameters monitored or inspected," and "acceptance criteria" program elements consistent with GALL AMP X.M1. Specifically, it was not evident to the staff how this enhancement related to the acceptance criterion recommendation for environmental fatigue calculations in the "acceptance criteria" program element of GALL AMP X.M1. It is also not evident to the staff how this enhancement related to the "preventive actions" and "parameters monitored or inspected" program elements in GALL AMP X.M1, which do not mention criteria for environmental calculations or assessments.

By letter dated June 30, 2010, the staff issued RAI B.3.1.1-3 requesting that the applicant confirm that the stated enhancement is being proposed to make the "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with GALL AMP X.M1. The applicant was also requested to clarify how this enhancement relates to the recommendations of the "acceptance criteria," "preventive actions," and "parameters monitored or inspected" program elements in GALL AMP X.M1.

In its response dated July 28, 2010, the applicant clarified that Enhancement 3 is proposed for the purpose of making the "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements consistent with those in GALL AMP X.M1. In regard to the relationship of the enhancement to the "preventive actions" program element, the applicant clarified that the enhancement will ensure that the program's monitoring methods will consider the impacts of the reactor water environment on the CUF values for the components that are monitored. The staff noted that the "preventive actions" program element of GALL AMP X.M1 recommends that maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of RCS components due to anticipated cyclic strains. The staff noted that the applicant's application of Enhancement 3 to the "preventive actions" program element is being proposed to ensure that the program's monitoring of the CUFs for RCPB components will take into account the environmental effects of the reactor coolant environment on the CUF values to maintain it below the design limit of 1.0.

Based on this review, the staff finds that the preventive actions, when subject to Enhancement 3, will be acceptable for implementation because: (1) the application of the enhancement will ensure that the monitoring of the CUF values will appropriately account for the impact of the reactor coolant environment on the CUF values for the components, (2) application of the enhancement will ensure that the implementation of the "preventive actions" program element will be consistent with the corresponding "preventive actions" program element in GALL AMP X.M1, and (3) the applicant has included this enhancement as Commitment No. 47 and has committed to implement this commitment prior to entering the period of extended operation.

In regard to the relationship of the enhancement to the "parameters monitored or inspected" and "monitoring and trending" program elements, the applicant clarified that the enhancement will ensure that the program's CUF monitoring methods will consider and apply the environmental fatigue life correction factor, F_{en}, adjustments to the CUF values for a sample of RCPB components that are identified as critical environmental fatigue locations. The applicant clarified that this is in conformance with the recommendations for identifying EAF analysis component locations, as given in NUREG/CR-6260. The staff noted that the "parameters monitored or inspected" program element of GALL AMP X.M1 recommends, in part, that the program should monitor all plant transients that cause cyclic strains and which are significant contributors to the fatigue usage factor and that the plant transients that cause significant fatigue usage for each critical RCPB component be monitored. The staff also noted that the "monitoring and trending" program element of GALL AMP X.M1 recommends that the program should monitor a sample of high fatigue usage locations and that the sample is to include the locations identified in NUREG/CR-6260, as a minimum, or propose alternatives based on a plant's specific configuration.

Based on its review, the staff finds that the CUF monitoring methods, when subject to Enhancement 3, will be acceptable for implementation because: (1) the applicant identified the critical RCPB locations for EAF analyses and has applied the F_{en} factors, (2) the enhancement will ensure the application of the program's cycle monitoring and CUF monitoring methods to the CUF values for those RCPB components that have been identified as the critical EAF locations, (3) this is consistent with the "parameters monitored or inspected" and "monitoring and trending" program elements of GALL AMP X.M1, and (4) the applicant has incorporated this enhancement in Commitment No. 47 and has committed to implement this commitment prior to entering the period of extended operation.

In regard to the relationship of the enhancement to the "acceptance criteria" program element, the applicant clarified that the enhancement was being proposed to ensure conformance with the "acceptance criteria" program element in GALL AMP X.M1. The applicant clarified that this was being proposed to ensure that, for the critical EAF RCPB locations, the monitoring of the CUF values for the components would be performed against the design code CUF limits, as adjusted using the design life adjustment factors developed for assessing the impact of reactor coolant environment on the fatigue life of the components. The staff noted that the "acceptance criteria" program element of GALL AMP X.M1 recommends that the program's acceptance criteria should maintain the fatigue usage below the design code limit considering environmental fatigue effects as described under the program description. The staff noted that the applicant's acceptance criteria, which will be modified by Enhancement 3, would ensure that the monitoring of the CUF values for the critical EAF analysis locations would be performed against F_{en}-adjusted CUF limits in the RCPB.

Based on its review, the staff finds the acceptance criteria, subject to Enhancement 3, acceptable for implementation because: (1) the application of the enhancement will ensure that the acceptance criteria on CUF monitoring of the critical EAF locations in the RCPB will be performed against appropriate F_{en}-adjusted CUF limits, (2) application of the enhancement will ensure that the implementation of the "acceptance criteria" program element is consistent with GALL AMP X.M1, and (3) the applicant has incorporated this enhancement in Commitment No. 47 and has committed to implement this commitment prior to entering the period of extended operation.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-3 and Enhancement 3 acceptable because: (1) the applicant described in detail how its Enhancement 3 is consistent with the recommendations of the GALL Report; and (2) the staff confirmed that when Enhancement 3 is implemented prior to the period of extended operation, the applicant's program will be consistent with the recommendations of GALL AMP X.M1, as described above. The staff's concern described in RAI B.3.1.1-3 is resolved.

Enhancement 4. LRA Section B.3.1.1 states an enhancement to the "corrective actions" program element. The staff noted that this enhancement expands on the existing program element to address the expanded review of RCPB locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit.

During the staff's review, it was not evident whether the stated enhancement is being made to make the "corrective actions" program element consistent with the corresponding program element in GALL AMP X.M1. It was also not apparent to the staff what is being enhanced, specifically whether the enhancement will involve the basis document or the implementing procedure. By letter dated June 30, 2010, the staff issued RAI B.3.1.1-4 requesting that the applicant confirm that the stated enhancement is being proposed to make the "corrective actions" program element consistent with that in GALL AMP X.M1. The applicant was also requested to clarify what will be enhanced.

In its response dated July 28, 2010, the applicant clarified that Enhancement 4 is being proposed to make the "corrective actions" program element consistent with that in GALL AMP X.M1. The applicant also clarified that the enhancement will ensure that new revisions to existing implementing procedures will be issued to include the review of additional RCPB locations, if the usage factor for one of the environmental fatigue sample locations approaches its design limit.

The staff noted that the "corrective actions" program element of GALL AMP X.M1 states:

> The program provides for corrective actions to prevent the usage factor from exceeding the design code limit during the period of extended operation. Acceptable corrective actions include repair of the component, replacement of

> the component, and a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the extended period of operation. For programs that monitor a sample of high fatigue usage locations, corrective actions include a review of additional affected RCPB locations. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

The staff noted that the applicant conservatively considers the EAF analysis locations in the RCPB to be high usage factor locations and Enhancement 4 ensures that the CUF monitoring would be applied to additional component locations if the monitored CUF value for an EAF analysis location was to reach the design limit. The staff noted that the implementation of Enhancement 4 will make the “corrective actions” program element consistent with the recommendation in GALL AMP X.M1 to include a review of additional RCPB component locations if an action limit on CUF monitoring is reached.

Based on its review, the staff finds the applicant’s response to RAI B.3.1.1-4 and Enhancement 4 acceptable because: (1) Enhancement 4 ensures that sample expansion of the program’s CUF monitoring activities will be applied to other locations if the monitored CUF for a critical EAF analysis component was to reach its design limit, (2) Enhancement 4 is consistent with the recommendations in the corresponding “corrective actions” program element in GALL AMP X.M1, and (3) the applicant has included this enhancement as Commitment No. 47 and has committed to implement this commitment prior to entering the period of extended operation. The staff has noted a concern as to whether the applicant verified that the locations per NUREG/CR-6260 are bounding as compared to other plant-specific locations (e.g., locations with a higher CUF value). The staff’s evaluation of the issue on the selection of the plant-specific locations is documented in SER Section 4.3.7.2. The staff’s concern described in RAI B.3.1.1-4 is resolved.

<u>Operating Experience</u>. LRA Section B.3.1.1 summarizes operating experience related to the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated the Metal Fatigue of Reactor Coolant Pressure Boundary Program has remained responsive to industry and plant-specific emerging issues and concerns. To support this statement, the applicant listed examples where it addresses NRC Bulletins 88-11 and 88-08. The applicant addressed concerns raised in NRC Bulletin 88-11 on pressurizer surge line thermal stratification by analyzing and demonstrating the acceptability of the CUF and by including the thermal stratification into the fatigue evaluation for the period of extended operation. Also, the applicant addressed concerns raised in NRC Bulletin 88-08 on thermal stresses in piping connected to the RCS by performing evaluations to ensure that the safety injection lines, normal and alternate charging lines, and the auxiliary spray lines would not experience failure. Based on this evaluation, the applicant implemented a leakage monitoring program for the safety injection lines. In addition, the applicant demonstrated that monitored transient cycles have not exceeded the imposed 40-year design limits and have been within their respective administrative 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 and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.3.1.1 provides the UFSAR supplement for the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 4.3-2. The staff also notes that the applicant committed (Commitment No. 47) to enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) include additional transients beyond those defined in the TSs and the UFSAR and expanding the fatigue monitoring program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring; (2) use a software program to automatically count transients and calculate cumulative usage on select components; (3) address the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant identified in NUREG/CR-6260; and (4) require a review of additional RCPB locations if the usage factor for one of the environmental fatigue sample locations approaches its CUF acceptance criterion limit. The staff verified that these commitment provisions specifically involve the four enhancements that the applicant proposed in LRA Section B.3.1.1, as amended, and by letter dated July 28, 2010.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary 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. 47 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as plant-specific:

- High Voltage Insulators
- Periodic Inspection
- Aboveground Non-Steel Tanks

- Buried Non-Steel Piping Inspection
- Boral Monitoring Program
- Nickel Alloy Aging Management

For the AMPs not consistent with or not addressed by the GALL Report, the staff performed a complete review of the plant-specific AMP to determine whether it was adequate to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in the following sections of this SER.

3.0.3.3.1 High Voltage Insulators

Summary of Technical Information in the Application. LRA Section B.2.2.1 describes the new High Voltage Insulators Program as plant-specific. The applicant stated that the High Voltage Insulators Program is a new condition monitoring program that manages the degradation of insulator quality at Salem due to the presence of salt deposits or surface contamination. The scope of the program includes high voltage insulators in the 500-kV switchyard and portions of the 13-kV buses. The applicant also stated that the High Voltage Insulators Program includes visual inspections to detect unacceptable indications of insulator surface contamination. The visual inspections will be performed on a twice per year frequency, will be effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant degradation. The applicant also stated that this program will be implemented prior to the period of extended operation so that the intended functions of components within the scope of license renewal will be maintained during 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.

Scope of the Program. LRA Section B.2.2.1 states that the High Voltage Insulators Program is a new program that manages the aging effect of degradation of insulator quality. The scope of the program includes insulators in the 500-kV switchyard ring bus and portions of the 13.8-kV buses. The high voltage insulators are those credited for supplying power to in-scope components for recovery of offsite power following an SBO.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the scope of the program should include the specific SCs of which the program manages aging. The staff determined that the specific commodity groups for which the program manages aging effects are identified (insulators in the 500-kV switchyard ring bus and portions of the 13.8-kV buses for recovery of offsite power following an SBO), which satisfies the criterion defined in SRP-LR Appendix A.1.2.3.1.

The staff confirmed that the "scope of the 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.2.2.1 states that the High Voltage Insulators Program is not a preventive or mitigative program. The High Voltage Insulators Program is a condition monitoring program that relies upon visual inspections of insulator surfaces in order to manage the degradation of insulator quality due to the presence of salt deposits or surface contamination.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state that condition monitoring programs do not rely on preventive actions and thus, preventive actions need not be provided. The staff notes that this is a condition monitoring program and that there is no need for preventive actions, consistent with SRP-LR Section A.1.2.3.2.

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.

Parameters Monitored or Inspected. LRA Section B.2.2.1 states that walkdowns are periodically conducted to visually inspect material conditions in the switchyards. Inspections of high voltage insulators will be performed visually to determine a threshold for implementing corrective actions. These inspections will detect the presence and extent of any aging degradation due to the presence of salt deposits. The applicant also stated that porcelain insulators typically have a shiny surface; if the surface is dull, then contamination is present. Typically heavy contamination will be apparent by the buildup at the base area of a vertical insulator. Similarly, for insulators in the dead-end horizontal configuration, significant drip marks are an indication that the location should be monitored. The applicant further stated that the most important area that signifies heavy contamination is when contamination is observed on the inside ridges of the underside of the bells. Evidence of salt deposits or surface contamination will be monitored and inspected to ensure high voltage insulator intended function during the period of extended operation.

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 state that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s). The parameters monitored or inspected should detect the presence and extent of aging effects.

The staff noted that surface contamination is the potential aging effect of high-voltage insulators and a buildup of contamination could enable the conductor voltage to track along the surface and can lead to insulator flashover. The staff determined that visual inspection is acceptable for detecting and managing the aging effects of salt deposits or surface contamination associated with high-voltage insulators and will ensure the component intended function during the period of extended operation.

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.2.2.1 states that system walkdowns in the switchyards are conducted periodically and include a visual inspection of high-voltage insulator surface conditions in accordance with system engineering walkdown procedures. These walkdowns will continue into the period of extended operation and will detect any aging degradation due to the presence of salt deposits or surface contamination. These inspections will be performed visually to determine a threshold for implementing corrective actions.

The applicant stated that high-voltage insulators within the scope of this program are to be visually inspected at least twice per year. This is an adequate period to detect aging effects before a loss of component intended function since experience has shown that aging degradation is a slow process. The applicant also stated that a twice per year inspection interval will provide multiple data points during a 20-year period, which can be used to characterize the degradation rate. The buildup of surface contamination is typically a slow, gradual process that is even slower for rural areas with generally less suspended particles and contaminant concentrations in the air than urban areas. Salem is located in a rural area, not near heavy industry that would provide a source for contaminants. The applicant further stated that there has only been one event associated with insulator contamination, which was not age-related or time-dependent. Therefore, operating history and plant location support a twice per year inspection frequency, which in turn provides reasonable assurance that the aging effect of degraded insulator quality will be detected prior to failure and loss of intended function.

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 state that the parameters to be monitored or inspected should be appropriate to ensure that the SCs intended function(s) 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 the buildup of surface contamination is a slow, gradual process and Salem is located in a rural area, not near heavy industry that would provide a source of contamination. There has only been one event associated with insulator contamination. The plant-specific operating experience supports a twice per year inspection frequency. The staff determined that visual inspection is an acceptable technique for inspecting surface contamination of insulators and a twice per year inspection frequency is adequate to ensure timely detection of aging effects.

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.2.2.1 states that monitoring activities will be prescribed by procedures that contain consistent qualitative criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy) and results will be documented providing a predictable extent of degradation. Visual techniques and a twice per year frequency are appropriate for monitoring high-voltage insulators and have been employed with success by transmission and distribution organizations. The applicant also stated that qualitative criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy) will allow a predictable extent and rate of surface contamination degradation. The results will be trended, from inspection to inspection, providing a basis for timely corrective actions such as insulator cleaning/washing, prior to a loss of insulator intended function.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which state that monitoring and trending activities should be described and they should provide predictability of the extent of degradation and thus effect 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 determined that trending for insulator surface contamination levels (e.g., slight, moderate, and heavy) will be documented and will provide a predictable extent of degradation. The result will be trended from inspection to inspection and will provide a basis for timely corrective actions prior to a loss of intended functions.

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.2.2.1 states visual inspection of high-voltage insulators will be prescribed by procedures that contain consistent qualitative criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy) and the results will be documented providing a predictable extent of degradation. Inspection findings are to be within the acceptance criteria of these procedures, to ensure that high-voltage insulator intended function is maintained under all CLB design conditions during the period of extended operation.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which state 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 determined that the applicant described acceptance criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy) in the plant procedures. Inspection findings are to be within the acceptance criteria of these procedures to ensure that high-voltage insulator intended function is maintained during the period of extended operation. 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.

Operating Experience. LRA Section B.2.2.1 summarizes operating experience related to the high-voltage insulators. The applicant stated that industry operating experience illustrates the potential for loss of insulator quality due to salt deposits and surface contamination on switchyard insulators. The applicant also stated that demonstrating the new High Voltage Insulators Program will be effective is achieved through objective evidence that shows the aging effect of degradation of insulation quality caused by the presence of salt deposits and surface contamination is being adequately managed. The applicant further stated that the following examples of operating experience provide objective evidence that the new High Voltage Insulators Program will be effective in assuring that the intended function will be maintained consistent with the CLB for the period of extended operation:

(1) In March 1993, Crystal River Unit 3 experienced a loss of the 230-kV switchyard (normal offsite power to safety-related buses) when a light rain caused arcing across salt-laden 230-kV insulators and opened switchyard breakers. In March 1993, the Brunswick Unit 2 switchyard experienced a flashover of some high-voltage insulators attributed to a winter storm. Since 1982, Pilgrim experienced several losses of offsite power when ocean storms deposited salt on the 345-kV switchyards, causing the insulator to arc to ground. The applicant further stated that in response to this industry experience, existing 6-month inspections of Salem 13-kV insulators were expanded to include the 500-kV insulators for salt contamination. The switchyard was inspected using thermography and corona detection equipment in the winter and summer of 2002, and no significant contamination buildup was found. The response and actions associated with this industry experience were revisited in 2003 following the effects of Hurricane Isabel. Switchyard insulator inspections were instituted along with contingency planning for an insulator cleaning strategy. The applicant further stated that steps for initiating inspection of switchyard insulator surfaces were added to severe weather abnormal operating procedures upon forecast of severe weather. This example provides objective evidence that industry operating experience will be applied toward this new program,

and corrective actions will be taken when the quality of insulator surfaces is threatened by storms and contamination.

(2) One plant-specific event occurred at Salem on September 18–19, 2003, when Hurricane Isabel passed a considerable distance to the south and west of the site. Strong winds with gusts in excess of 60 miles per hour (mph) caused switchyard insulators to become coated with salt. The rain had stopped prior to the strongest winds, leaving the salt spray to dry on switchyard insulators. Both Salem units operated throughout the storm. The combination of salt on the insulator surface and atmospheric moisture subsequently caused a flashover. The applicant also stated that circuit breakers opened as designed to isolate the fault on the Salem end of the line, without effect on Salem plant equipment. Another insulator flashover occurred shortly thereafter with no effect on plant operation. In response to the switchyard faults, both Salem units were manually taken offline on September 20th. The high-voltage insulators were subsequently cleaned/washed prior to returning the units to operation. The applicant further stated that this event demonstrates that corrective actions are taken when high-voltage insulator degradation is found and because this is the only high-voltage insulator-related event of record, flashover due to salt contamination of insulators at Salem is considered rare.

(3) Visual inspection of Salem switchyard high-voltage insulators is performed twice per year for evidence of salt and contamination. These inspections have been in place since 1996 and have not found or observed degraded insulator quality other than “slight” surface contamination, even during periods of excessively dry weather, which would warrant cleaning or other corrective measures. This component history demonstrates that minor contamination is washed away by rainfall or snow, and cumulative buildup has not been experienced and is not expected to occur (with the exception of infrequent storms like Hurricane Isabel). Visual inspection results for high-voltage insulators are evaluated as part of transmission and distribution outage inspections as well as switchyard system walkdowns. This example provides objective evidence that the aging effect of degraded insulation quality is capable of being detected and that the mechanisms of salt deposit and surface contamination on high-voltage insulators will be managed prior to loss of intended function. The applicant further stated that the Salem operating experience for the High Voltage Insulators Program provides sufficient confidence that the implementation of the High Voltage Insulators Program will effectively identify degradation prior to failure.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which state that operating experience with the existing program should be discussed. The operating experience should provide objective evidence to support the conclusion that the effect of aging will be adequately managed so that the SC intended function(s) will be maintained during the period of extended operation.

The staff finds that although the High Voltage Insulators Program is a new program with no operating experience for implementation, the applicant has captured insulator operating experience through reviewing industry operating experience and onsite documentation. The applicant reviewed industrial as well as plant-specific operating experience to provide the objective evidence that the new High Voltage Insulators Program will be effective in assuring that the intended function will be maintained consistent with the CLB for 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. 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.2.2.1 provides the UFSAR supplement for the High Voltage Insulators Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff notes that the applicant committed (Commitment No. 41) to implement the new High Voltage Insulators Program prior to entering the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's High Voltage Insulators 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).

3.0.3.3.2 Periodic Inspection

Summary of Technical Information in the Application. LRA Section B.2.2.2 describes the new Periodic Inspection Program as a plant-specific program. The applicant stated that the Periodic Inspection Program manages stainless steel, aluminum, and copper alloy piping and ducting components and tanks for loss of material; heat exchangers for the reduction of heat transfer; and elastomers for hardening and loss of their strength when exposed to wetted (including treated borated water) environments. The applicant also stated that this program will manage cracking of the stainless steel EDG engine exhaust expansion joints. The applicant further stated that the program includes visual inspections and ultrasonic wall thickness measurements to detect loss of material.

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.

Scope of the Program. LRA Section B.2.2.2 states that the scope of the Periodic Inspection Program monitors aging effects in stainless steel, aluminum, copper alloy piping, piping components, piping elements, heat exchanger components, tanks and ducting components, and elastomers not included in other AMPs.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the scope of the program should include the specific SCs for which the program manages the aging.

The staff concluded that the scope of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.1 because it includes specific SCs for which it will manage aging during the period of extended operation.

The staff confirmed that the "scope of the 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.2.2.2 states that the Periodic Inspection Program is a condition monitoring program and does not include activities for prevention or mitigation of aging effects.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state that for condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided.

The staff concluded that the "preventive actions" element of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.2 because the Periodic Inspection Program is a condition monitoring program and does not need to include preventive actions.

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.

Parameters Monitored or Inspected. LRA Section B.2.2.2 states that the Periodic Inspection Program will detect: (1) loss of material in stainless steel, aluminum, and copper alloys; (2) hardening and loss of strength in elastomers; (3) cracking of EDG engine exhaust expansion joints; and (4) the presence and extent of fouling that could result in reduction of heat transfer of heat transfer surfaces. The applicant also stated that the program includes provisions for visual inspections and ultrasonic wall thickness measurements to detect loss of material.

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 state that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SCs intended function(s). The SRP-LR also states that for a condition monitoring program, the parameters monitored or inspected should detect the presence and extent of aging effects.

The staff concluded that the "parameters monitored or inspected" program element of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.3 because the applicant identified and linked specific degradations to particular SCs and stated that it will monitor their condition through visual or volumetric inspections, which is appropriate for assuring that they can fulfill their intended functions.

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.2.2.2 states the Periodic Inspection Program will use visual inspections and ultrasonic wall thickness measurements to detect aging effects of components within the scope of this program prior to loss of their intended function. The visual inspections will focus on: (1) loss of material in metals identified within the scope of the program; (2) cracking of EDG engine exhaust expansion joints; (3) fouling that could result in reduction of heat transfer on heat exchanger coils; (4) hardening and loss of strength in elastomers, where visual inspections may be augmented by physical manipulations. The applicant also stated that visual inspections and ultrasonic measurements will be performed on a representative sample of components, made available based on system operating conditions, plant operating experience, and accessibility during their periodic disassembly. The applicant further stated that a 10-year inspection frequency is established based on plant and industry operating experience, which indicates that a 10-year inspection frequency will be adequate to detect loss of material prior to loss of the component's intended function.

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 state that the program should: (1) identify aging effects linked to SCs and monitor these before loss of their intended functions; (2) monitor and inspect appropriate parameters, (3) designate inspection methods, techniques (i.e., visual, volumetric, surface inspection), their frequency, population criteria (i.e., similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects), sample size (i.e., its basis and bias), data collection, and timing based on plant-specific or industry-wide operating experience, (4) maintain the plant's redundancy, diversity, and defense-in-depth consistent with the CLB; and (5) describe "when," "where," and "how" program data is collected.

The staff concluded that a 10-year inspection frequency is appropriately selected and established because it is based on plant-specific and industry operating experience. After further reviews and comparisons of the "detection of aging effects" program element in LRA Section B.2.2.2 with that of SRP-LR Section A.1.2.3.4, the staff determined the need for additional clarifications to assess its consistency. This resulted in the issuance of the following RAIs.

SRP-LR Appendix A, Section A.1.2.3.4 states that the program element describes "when," "where," and "how" program data will be collected (i.e., all aspects of activities to collect data as part of the program). The "detection of aging effects" program element of the LRA AMP states that the parameters monitored and inspected include visual inspections of component surfaces and ultrasonic wall thickness measurements to identify loss of material. It was not clear to the staff how these techniques would identify loss of material in aluminum components. By a letter dated June 10, 2010, the staff issued RAI B.2.2.2-1 requesting that the applicant explain how visual inspections could identify aging effects in aluminum components. In its response dated July 8, 2010, the applicant stated that aluminum components exposed to air which are included in the Periodic Inspection Program are immune to general corrosion due to the presence of an aluminum oxide layer on the surface of the metal, but that they are subject to loss of material due to pitting and crevice corrosion. The applicant also stated that heat transfer surfaces of aluminum heat exchanger fins and tubes are prone to reduction of heat transfer due to fouling. For both pitting and crevice corrosion and reduction of heat transfer, the applicant stated that it will use visual inspection techniques to identify the appropriate aging effects (i.e., pitting and crevice corrosion by abnormal surface roughness on aluminum component surfaces and detection of fouling by accumulation of dirt, grease, or other foreign material on heat exchanger fins and heat conducting surfaces). The applicant further stated that once these aging effects are identified, they will be noted and addressed through the corrective action program. The staff finds the applicant's response acceptable because visual inspection is an acceptable technique for identifying loss of material due to pitting and crevice corrosion on aluminum components and for identifying fouling on aluminum heat transfer surfaces. The staff's concern described in RAI B.2.2.2-1 is resolved.

When the staff compared the LRA to SRP-LR Appendix A, Section A.1.2.3.4 regarding the visual inspection and potential physical manipulation of elastomers for hardening and loss of strength, it was not clear to the staff: (1) what factors would be used to determine the need to augment visual inspections of elastomers with physical manipulations, (2) the characteristics assessed by the physical manipulations, and (3) how collected information would be quantified or otherwise used to assess component longevity. By letter dated June 10, 2010, the staff issued RAI B.2.2.2-2 requesting that the applicant clarify the process for determining the need for physical manipulation of elastomer components to assist visual inspections, clarify the characteristics assessed by the physical manipulations, and discuss how collected information would be quantified or otherwise used to assess component longevity. In its response dated July 8, 2010, the applicant stated that elastomer components included in the Periodic Inspection Program are subject to the aging effect of hardening and loss of strength. The applicant stated that physical manipulation to assist in the detection of hardening is determined from the results of the initial visual inspection, which checks the material for cracking, flaking, shrinkage, swelling, or physical damage. The applicant also stated that evidence of aging degradation will lead to that material being placed into the corrective action program. The staff finds the applicant's response acceptable because the applicant has clarified that physical manipulation will be used to verify aging of elastomers if signs of degradation are present, which is an acceptable technique for determining if an elastomer is aging. The staff's concern described in RAI B.2.2.2-2 is resolved.

When the staff compared the LRA to SRP-LR Appendix A, Section A.1.2.3.4 recommendations on sampling, it was unclear to the staff how the applicant defined its "representative sample," population criteria, and population size. On August 18, 2010, the staff held a telephone conference with the applicant (ADAMS Accession No. ML102460095) to clarify how the Periodic Inspection Program's sampling methodology, including how the population for each of the material-environment-aging effect combinations is being selected, and what type of engineering, design, or operating experience considerations would be used to select the sample of components for both the scheduled and supplemental inspections. During this discussion, the applicant stated that the program will ensure that for each material, environment, and aging effect combination, the applicant will conduct representative inspections as directed by formal preventive maintenance or recurring tasks within the work management system. The applicant also stated that the intent is to use existing preventive maintenance or recurring task activities augmented with new recurring task activities to address inspection of material, environments, and aging effects not adequately addressed by the current activities. The applicant further stated that if adverse conditions are identified, the condition will be entered into a corrective action program, discussed in the LRA, and appropriate actions will be directed including identifying and evaluating the cause and extent of the condition(s). The staff finds the applicant's response acceptable and the "detection of aging effects" program element consistent with the corresponding element of SRP-LR Section A.1.2.3.4 because its "representative sample" will include inspections for each material, environment, and aging effect combination and that when degradation is found, it will be entered in the corrective action program.

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.2.2.2 states that the Periodic Inspection Program performs visual inspections for loss of material, loss of strength, hardening, cracking, and reduction of heat transfer for selected materials and components, described under the "scope of the program" program element, and ultrasonic wall thickness measurements to detect aging effects. The applicant also stated that these periodic inspections are performed on population samples with frequencies based on industry and plant experience and are effective in identifying the extent of component degradation prior to the loss of their intended function. The applicant further stated that identified degradations will be entered into the corrective action program to determine their impact on the component's intended function, including any required repairs or subsequent monitoring and trending requirements.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Appendix A, Section A.1.2.3.5, which state that monitoring and trending activities should predict the extent of degradation to trigger timely corrective or mitigative actions. The SRP-LR also states that plant-specific and industry-wide operating experience may be considered in evaluating appropriate techniques and frequencies. The SRP-LR further states that the program element should support quantification of aging indicators and parameters monitored to compare ongoing collected data for trending and future predictions.

Following the reviews and comparisons between the LRA Section B.2.2.2 "monitoring and trending" program element with that of SRP-LR Section A.1.2.3.5, the staff concluded that the applicant's proposed visual inspections and ultrasonic wall thickness measurements together with initiation of corrective actions would be able to determine the extent of degradation and provide timely corrective or mitigative actions because the applicant is: (1) using techniques that would be able to determine the extent of degradation and (2) has satisfactorily described an appropriate method in which the data will be collected and evaluated.

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 2.2.2 states that the acceptance criteria are based on the following for a given aging effect: (1) for loss of material, acceptance criteria are based on the original equipment design wall thickness minus allowances for corrosion and degradations; (2) for reduction of heat transfer, acceptance criteria are based on identification of fouling on the external heat transfer surfaces of cooling coils; (3) for standby diesel expansion joint cracking, acceptance criteria are based on preventing exhaust gas leakage that could impact engine operation; and (4) for hardening and loss of strength of elastomers, acceptance criteria are based on visual indications of degradation such as cracking, tears, or perforations in the material, often augmented with physical manipulations to assure the material's integrity or the need for its replacement.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which state that the acceptance criteria of the program and its basis should be described so that the need for corrective actions is evaluated. The SRP-LR also states that acceptance criteria should be specific and quantifiable to ensure that the SCs intended function(s) remain (including replacement) under all CLB design conditions during the period of extended operation. The SRP-LR further states that the program should include a methodology for analyzing the results against applicable acceptance criteria.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Appendix A, Section A.1.2.3.6 and determined the need for additional clarifications to assess consistency of the "acceptance criteria" program element, which resulted in the issuance of the following RAI.

SRP-LR Appendix A, Section A.1.2.3.6 states that the acceptance criteria of the program and its basis should be described. In the "acceptance criteria" program element of the LRA AMP, it states that acceptance criteria for loss of material are based on the original equipment design wall thickness and any corrosion allowance requirements. It is not clear to the staff what the acceptance criteria are for determining the effects of aging on aluminum components. By a letter dated June 10, 2010, the staff issued RAI B.2.2.2-3 requesting that the applicant clarify the acceptance criteria for determining the effects of aging on aluminum components. In its response dated July 8, 2010, the applicant stated that focused visual inspections will examine aluminum surfaces and identify: (1) for loss of material, pitting, or abnormal surface roughness; and (2) for reduction in heat transfer and evidence of surface fouling from the presence of dirt, grease, or other foreign material. The applicant stated that any evidence of this type of degradation beyond minor surface corrosion or fouling will be entered into the corrective action program for further engineering evaluation. The applicant also stated that this evaluation will determine a component’s acceptability for continued service with acceptance criteria based on the component’s design requirements and its intended functions. The applicant further stated that components determined to be incapable of performing their intended function will be repaired or replaced. The staff finds the applicant’s response acceptable because the applicant has identified appropriate criteria for determining whether aging is occurring for aluminum components and against which the need for corrective actions will be evaluated. The staff’s concern described in RAI B.2.2.2-3 is resolved. The staff concluded that the “acceptance criteria” element of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.6 because it includes specific criteria that are appropriate for determining when loss of material, loss of strength, hardening, and cracking are occurring for the components within the scope of the program and for identifying when corrective actions are required.

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.

<u>Operating Experience</u>. LRA Section B.2.2.2 summarizes operating experience related to the Periodic Inspection Program. The applicant stated that the proposed Periodic Inspection Program will be effective in assuring that the intended functions of systems and components within the scope of the program will be maintained for the period of extended operation. To support this statement, the applicant provided several examples of periodic visual inspections including: (1) stainless steel, aluminum, and copper alloy ventilation system components exposed to plant and outdoor air; (2) stainless steel piping exposed to external salt contamination from the Delaware River, following feedback from industry operating experience observations (Institute of Nuclear Power Operations (INPO) Significant Event Notification (SEN) 226, “SCC on a Portion of Safety Injection System Piping”); and (3) elastomer components in the fuel handling building exhaust fan. In the first and second examples, the applicant stated that the results of the inspections were satisfactory and that no corrective actions were required. In the third example, the applicant also stated that visual inspection of a degraded elastomer that was previously repaired prompted its replacement. The applicant further stated that these examples demonstrate that these types of inspections performed by system owners are objective and adequate to evaluate the condition of the systems or components.

The staff reviewed this information against the acceptance criteria in SRP-LR Appendix A, Section A.1.2.3.10, which state that 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 SCs 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.2.2 provides the UFSAR supplement for the Periodic Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 42) to implement the new Periodic Inspection Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Periodic Inspection Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Aboveground Non-Steel Tanks

Summary of Technical Information in the Application. LRA Section B.2.2.3 describes the new Aboveground Non-Steel Tanks Program as plant-specific. The applicant stated that the program is a condition monitoring program that is intended to manage aging of non-steel tanks. The applicant also stated that the program includes visual inspections of the external tank surfaces above their foundation interface and of the grout and sealant materials at the tank/foundation interface. The applicant further stated that UT will be used to monitor loss of material due to corrosion on tank bottoms. The staff notes that the applicant's inspection procedures ensure that the caulk/sealant joint between the tank and foundation interface is visually inspected during the inspection of the tank.

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.

Scope of the Program. LRA Section B.2.2.3 states that all in-scope aboveground non-steel tanks are covered in this program. The applicant's coverage of stainless steel in this program is consistent with the GALL Report definition of non-steel as a construction material being distinguished from carbon steel alloys.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the program should include the specific SCs for which the program manages aging.

The staff reviewed the LRA and confirmed that the applicant's program has appropriately included outdoor, aboveground, non-steel tanks consistent with the guidance in the SRP-LR. The staff noted that other non-steel tanks within the scope of license renewal (e.g., volume control tank, boric acid and batching tank, gas decay tanks) are located indoor and are managed under different AMPs (e.g., Water Chemistry and Closed-Cycle Cooling Water System programs). Given that each of the other non-steel tank AMR line items will be evaluated during the review of the LRA, the staff determines the applicant's scope of the program acceptable for the program managing the aging.

The staff confirmed that the "scope of the 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.2.2.3 states that the program is a condition monitoring program based on visual inspections and UT of inaccessible tank bottom surfaces. The applicant stated that the program does not include activities for prevention or mitigation of aging effects.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state that for condition monitoring programs, preventive activities do not need to be included in the program.

The staff reviewed the program and confirmed that for the materials (e.g., stainless steel, grout) and environments (e.g., air-outdoor, soil) included, it is appropriate that this is a condition monitoring program without activities for corrosion mitigation or for corrosion prevention. Therefore, the staff determines the applicant's preventive actions are appropriate for the program managing the aging.

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.

Parameters Monitored or Inspected. LRA Section B.2.2.3 states that the program includes activities to detect the presence and extent of aging effects including general loss of material, pitting, and crevice corrosion prior to the in-scope tank's loss of intended function. The applicant stated that the methods that monitor for those aging effects are visual inspection and UT. The applicant also stated that UT will quantitatively measure wall thickness of tank bottoms and that information will be used to determine loss of material due to degradation of the internal surface. The applicant further stated that the visual inspection of the grout and sealant materials will detect loss of material.

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 state that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s) and for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff noted that the use of ultrasonic measurements and visual inspections is consistent with standard industrial practices and the parameters monitored in GALL AMP XI.M29, "Aboveground Steel Tanks," and has been proven to be effective in detecting significant losses of material due to the corrosion effects covered in the applicant's program. Therefore, the staff determines that the parameters to be inspected by the applicant appropriate for the aging effects addressed.

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.2.2.3 states that direct visual inspection will detect significant loss of material due to pitting and/or crevice corrosion prior to loss of an in-scope tank's intended functionality. The applicant stated that the UT method will be applied to the inside surfaces to inspect tank bottoms for thickness reduction due to corrosion. The applicant also stated that the visual inspection of the grout and sealant materials will be conducted to detect signs that water could potentially get under the tank bottom. The applicant further stated that the visual inspections will be conducted with 5-year intervals and that the UT will be conducted for each in-scope tank bottom prior to 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 state that detection of aging effects should occur before there is a loss of the SC intended function(s). The criteria also state that parameters to be monitored or inspected should be appropriate to ensure that the SC intended function will be adequately maintained for license renewal under all CLB design conditions. The criteria further state that a program based solely on detecting SC failure should not be considered as an effective AMP for license renewal. The criteria state that this program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program). The criteria continue by stating that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The staff confirmed that the use of the applicant's methods are appropriate for detecting the aging effects covered in the program by comparing them to GALL AMP XI.M29 and that the combined use of visual inspections and UT provide sufficient detection methods to monitor corrosion effects prior to loss of the tank's intended function. Therefore, the staff determines that the parameters being used to detect the aging effects are appropriate for the aging effects addressed.

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.2.2.3 states that the program's visual and ultrasonic examination inspections are based on industry and plant-specific operating experience. The applicant stated that wall thickness measurements will be compared to design requirements to determine if significant loss of material degradation is occurring. The applicant also stated that any significant corrosion detected as part of the inspections of this program will be entered into the corrective action program to determine the impact on the tank's intended function, required repair, and further monitoring and trending requirements.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which state that monitoring and trending activities should be described and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. The criteria also state that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The criteria further state that this program element describes “how” the data collected are evaluated and may also include trending for a forward look, including an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection will occur before a loss of SC intended function.

The staff considers the applicant’s coverage of this program element to be adequate because the applicant’s description of the program includes the application of corrosion monitoring and engineering analysis when corrosion is detected on in-scope components, which is consistent with the guidance in the SRP-LR. While the applicant’s program description did not specifically discuss predicting the rate of degradation, it did state that one aspect of the corrective action program is to further monitor and trend requirements. The staff noted that the applicant’s monitoring methods are adequate to ensure that corrosion issues can be addressed prior to loss of component functionality because the applicant’s method of inspection and frequency of sampling is consistent with industry and plant-specific operating experience and GALL AMP XI.M29. Therefore, the staff determines that the parameters being monitored or trended are appropriate for the aging effects addressed.

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.2.2.3 states that the acceptance criteria for the inspections that result in a quantitative value are the original equipment design wall thickness and corrosion allowance. The applicant stated that the acceptance criteria for visual inspections are qualitative unless indications of significant pitting, crevice corrosion, or other significant degradation are present which will result in an evaluation to quantify the material loss which is then compared to the applicable design requirements. The applicant also stated that inspections are performed by qualified personnel in accordance with approved station procedures.

The staff reviewed the applicant’s “acceptance criteria” program element against the criteria in SRP-LR Section A.1.2.3.6, which state the acceptance criteria of the program and its basis should be described, including ensuring that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. Acceptance criteria could be specific numerical values or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited. The criteria also state that acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads. The criteria further state that qualitative inspections should be performed to same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site-specific programs.

The staff considers the applicant’s coverage of this program element to be adequate because the applicant’s program description includes details on the method to be followed in response to observed corrosion effects, which is consistent with the guidance in the SRP-LR. The staff notes that the applicant’s program relies on established acceptance criteria, such as the original manufacturer’s specifications, including wall thickness for the specific component type and materials to be covered. The staff also notes that qualified personnel are used to perform inspections in accordance with approved plant procedures. Therefore, the staff determines that the acceptance criteria being used to evaluate aging effects are appropriate for the aging effects addressed.

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.

Operating Experience. LRA Section B.2.2.3 summarizes operating experience related to the Aboveground Non-Steel Tanks Program. In one example of operating experience, the applicant stated that through a process of multiple visual inspections, corrective actions were taken which involved draining a demineralized water storage tank, conducting internal visual inspections and UT, and replacing the tank bottom due to a through-wall hole caused by pitting in the tank bottom. The applicant also stated that after the bottom was replaced, the base perimeter was sealed to the cement support slab. In addition, the base perimeter seal on the other demineralized water tank was also replaced to minimize possible water intrusion under the base of the tank. The applicant further stated that based on industry operating experience, visual inspections were conducted to address the potential for accelerated corrosion due to salt contamination from the Delaware River with resulting visual inspections conducted in 2002, 2006, and 2008 revealing no age-related degradation. The applicant stated that in over 30 years of operating experience, there has been no degradation of the in-scope tank’s external surfaces exposed to the outdoor air environment.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which state that the operating experience information provided should provide objective evidence that the effects of aging will be adequately managed so that the intended function(s) of the in-scope SCs are 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 operating experience related to the applicant’s program demonstrates that it can adequately manage the detrimental 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.2.2.3 provides the UFSAR supplement for the Aboveground Non-Steel Tanks Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 43) to implement the new Aboveground Non-Steel Tanks Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant’s Aboveground Non-Steel Tanks 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).

3.0.3.3.4 Buried Non-Steel Piping Inspection

Summary of Technical Information in the Application. LRA Section B.2.2.4 describes the existing Buried Non-Steel (i.e., stainless steel and concrete) Piping Inspection as a plant-specific AMP. The applicant stated that the Buried Non-Steel Piping Inspection Program is a condition monitoring program used to manage buried reinforced concrete piping and components in the service water and circulating water systems as well as the buried stainless steel penetration bellows (a portion of the fuel transfer tube) between the containment structure and the fuel handling building, including the penetration sleeves, exposed to an external soil or groundwater environment for cracking, loss of bond, increase in porosity and permeability, and loss of material. The applicant also stated that the program relies on visual inspections conducted as part of opportunistic and focused excavations of buried, in-scope piping, and components. The applicant further stated that the inspections will identify coating degradation, if coated, or base metal corrosion.

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.

Scope of the Program. LRA Section B.2.2.4 states that the Buried Non-Steel Piping Inspection Program is an existing program that manages the aging effects of cracking, loss of bond, loss of material, and increased porosity and permeability. The applicant stated that the program covers buried reinforced concrete piping and components in the service water and circulating water systems as well as the buried stainless steel penetration bellows between the containment structure and the fuel handling building, including the penetration sleeves.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the program should include the specific SCs for which the program manages aging.

The staff reviewed the applicant's description of aging effects and the systems and components to be covered by this program. The staff determines that the LRA provides a list of the specific aging effects to be managed as well as all component types and systems that are covered by this program.

The staff confirmed that the "scope of the 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.2.2.4 states that this program is a condition monitoring program that relies on opportunistic and focused inspections, and it is not a preventive or mitigative program.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state that for condition monitoring programs, preventive activities do not need to be included in the program.

The staff reviewed the program and confirmed that is a condition monitoring program without activities for corrosion mitigation or for corrosion prevention. The staff notes that the applicant stated in the program description that, "Inspection of buried components identifies coating degradation, if coated, or base metal corrosion, if uncoated." The staff determines that whether the pipe coating is credited or not credited does not impact the evaluation of this program in that if it is coated, coating degradation is an inspection parameter.

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.2.2.4 states that the program includes activities to detect the presence and extent of cracking, loss of bond, and increases in porosity and permeability of the in-scope buried piping and components. The applicant stated that the inspection covers coating degradation if piping or components are coated and base material degradation if piping or components are uncoated. The applicant also stated that this program is not a performance monitoring program nor is it a preventive or mitigative program.

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 state that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s) and for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff noted that the applicant's intended use of visual inspection is consistent with standard industrial practices and GALL AMP XI.M34, "Buried Piping and Tanks Inspection," and has been proven to be effective in detecting significant losses of material due to the corrosion effects covered in the applicant's program. The staff considers the applicant's coverage of this program element to be adequate because the description of parameters being monitored is sufficient and is consistent with conventional industry parameters applicable for corrosion evaluations.

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.

<u>Detection of Aging Effects</u>. LRA Section B.2.2.4 states that the use of visual inspections to detect the aging effects being managed by this program is in accordance with accepted industrial standards. The applicant stated that the visual inspection process will, if necessary, include engineering evaluations and the consideration of expanded inspection methods. The applicant also stated that at least one opportunistic or focused inspection will be performed within 10 years prior to the period of extended operation and within the first 10 years of the period of extended operation. The applicant further stated that plant operating experience (i.e., no failures of buried non-steel piping due to external aging effects) supports this frequency of inspection.

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 state that detection of aging effects should occur before there is a loss of the SC intended function(s). The criteria also state that parameters to be monitored or inspected should be appropriate to ensure that the SC intended function will be adequately maintained for license renewal under all CLB design conditions. The criteria further state that a program based solely on detecting SC failure should not be considered as an effective AMP for license renewal. The criteria state that this program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program). The criteria continue by stating that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The staff confirmed that the use of the applicant's methods are appropriate for detecting the aging effects covered in the program by comparing them to GALL AMP XI.M34, "Buried Piping and Tanks Inspection," and that the use of visual inspections provides sufficient detection methods to monitor degradation of coatings and corrosion effects prior to loss of the buried non-steel piping intended function or failure. Additionally, the program specifies the periodicity of the inspections which are justified by plant-specific operating experience, location of the inspections relative to material type and risk ranking, and that inspections will be performed by excavated direct inspection of the pipe. Therefore, the staff determines that the parameters being used to detect the aging effects are appropriate for the aging effects addressed.

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.2.2.4 states that, based on plant-specific and industry operating experience, opportunistic and focused inspections are appropriate and adequate to detect aging effects prior to piping and components loss of intended function. The applicant stated that significant degradation identified by the visual inspections will be entered into the corrective action program and its engineering staff will quantify the results and either demonstrate acceptability or specify a repair or replacement. The applicant also stated that engineering evaluations will determine the need for follow-up exams to monitor progression of degradation, ensuring that inspections will occur prior to loss of function. The applicant further stated that by trending the data, its engineering staff will determine if the sample size must be expanded to determine the extent of degradation or if the frequency of inspections is acceptable.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which state that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. The criteria also state that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The criteria further state that this program element describes "how" the data collected are evaluated and may also include trending for a forward look, including an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection will occur before a loss of the SC intended function.

The staff considers the applicant's coverage of this program element to be adequate because the applicant's description of the program includes the application of engineering analysis, corrosion monitoring, and trending when corrosion is detected on in-scope components. The staff notes that the applicant's monitoring and trending methods are adequate to ensure that corrosion issues can be addressed prior to loss of component functionality and inspection frequencies will be adjusted by engineering evaluation if necessary based on inspection results.

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.2.2.4 states that the acceptance criteria to be applied in this program are the applicable regulatory or industry requirements for the respective piping and component being inspected. The applicant stated that the specific acceptance criteria relating to localized pipe wall thinning is contained in engineering documents and is used in engineering evaluations of observed corrosion. The applicant also stated that since the visual inspection process and acceptance criteria are qualitative, that in instances where significant corrosion is observed by visual inspection, engineering assessments will be used as well as additional evaluation methods to quantify the material loss and compare it to the applicable design requirements. The applicant further stated that inspections are performed by qualified personnel in accordance with approved procedures.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which state the acceptance criteria of the program and its basis should be described, including ensuring that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited. The criteria also state that acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads. The criteria further state that qualitative inspections should be performed to the same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site-specific programs.

The staff considers the applicant's coverage of this program element to be adequate because: (1) the applicant's program description includes details on the method to be followed in response to observed corrosion effects, (2) it relies on established acceptance design based criteria for the specific component and materials to be covered which will be evaluated by engineering, and (3) it relies on standard industry practices. The staff also noted that qualified personnel are used to perform inspections in accordance with approved plant procedures. Therefore, the staff determines that the acceptance criteria being used to evaluate aging effects are appropriate for the aging effects addressed. 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.

The staff notes that even though the Buried Non-Steel Piping Inspection Program is a plant-specific program, the applicant has demonstrated consistency with each of the program elements in GALL AMP XI.M34 except that the materials are non-steel (i.e., reinforced concrete, stainless steel) while the scope of GALL AMP XI.M34 includes only steel components (e.g., steel, gray cast iron, ductile cast iron). Based on recent industry operating experience, the staff requires further information related to the applicant's use of cathodic protection and coatings, and the quality of backfill in the vicinity of buried pipe. The staff issued RAIs B.2.1.22 and B.2.1.22-02, and its evaluation is documented in the "operating experience" program element. The applicant's response to these RAIs may impact the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements.

Operating Experience. LRA Section B.2.2.4 summarizes operating experience related to the Buried Non-Steel Piping Inspection Program. The applicant stated that no underground leaks have developed as a result of failure of the external surface of in-scope buried piping. The applicant also stated an instance of operating experience that involved the detection of an installation defect when a failed pipe was excavated and an opportunistic inspection was conducted. During the audit, the applicant stated that this example of operating experience concerned piping in the service water header joints which are internally inspected once every 3 years, with specific areas of higher susceptibility inspected every 18 months.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which state that the operating experience information provided should provide objective evidence that the effects of aging will be managed adequately so that the intended function(s) of the in-scope SCs are maintained during the period of extended operation.

Given that there have been a number of recent industry events involving leakage from buried or underground piping, the staff needed further information to evaluate the impact that these recent industry events might have on the applicant's Buried Piping and Tanks Inspection Program. By letter dated August 6, 2010, the staff issued RAI B.2.1.22 requesting that the applicant provide information regarding how it will incorporate industry operating experience into its AMRs and AMPs.

In its response dated September 7, 2010, the applicant stated that inspections of the coating and external surfaces of buried piping are conducted at locations and at a periodicity as informed by recent industry operating experience, risk-ranking in accordance with NACE and EPRI guidelines, and the NEI Industry Initiative on Buried Piping. The applicant also stated that it has committed to conduct excavated visual inspections of at least 8 linear feet of buried pipe (when practical) in each material group prior to entry into the period of extended operation and each 10-year period after entry into the period of extended operation.

Based on its review, the staff determined that it does not have sufficient information to find the applicant's response acceptable. By letter dated October 12, 2010, the staff issued follow-up RAI B.2.1.22-02 requesting that the applicant:

(a) define what is meant by excavating 8 feet of pipe "when practical," state what alternative inspection means will be used to determine the condition of the buried pipe and its coatings if the inspection of at least 8 feet of pipe were determined to be impractical, or justify why inspecting less than 8 feet is sufficient to provide a reasonable assurance of the condition of the pipe

(b) provide details on the quality of backfill in the vicinity of in-scope buried pipes

In its response dated November 10, 2010, the applicant stated that:

(a) the term "when practical" was not necessary and it has been stricken from the response, thus there was no need to state an alternate inspection means or to justify inspections of less than 8 feet

(b) plant-specific procedures require that bedding (i.e., backfill) material within 6 inches of the pipe be granular chrome ore or granular limestone, and analysis of the backfill removed during the 2010 inspections of auxiliary feedwater and compressed air lines indicate that the material met the plant-specific requirements

The staff finds the applicant's collective responses to RAIs B.2.1.22 and B.2.1.22-02 (as they pertain to buried non-steel piping inspections) acceptable because in addressing recent industry and plant-specific operating experience, the applicant: (a) is risk-ranking piping inspection locations based on industry standards including recent operating experience; (b) has stricken the term "when practical" from its RAI response which will ensure each excavation will expose at least 8 feet of pipe in all cases; (c) will conduct an excavated visual inspection of pipe in each material group prior to entry into the period of extended operation and each 10-year period after entry into the period of extended operation; (d) has plant-specific procedural requirements for backfill material that, based on its granular nature, can ensure no damage to piping will occur; (e) has inspection requirements for backfill when excavations are conducted to ensure that plant-specific backfill procedure requirements are being met; and (f) recently completed inspections have shown that the backfill requirements are being met. The staff's concerns described in RAIs B.2.1.22 and B.2.1.22-02 are resolved. Open Item OI 3.0.3.2.10-1 is closed.

Based on its audit, the review of the application, and review of the applicant's collective responses to RAIs B.2.1.22 and B.2.1.22-02 (as they pertain to buried non-steel piping inspections), the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.2.4 provides the UFSAR supplement for the Buried Non-Steel Piping Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2.

The staff also notes that the applicant committed (Commitment No. 44) to enhance the existing Buried Non-Steel Piping Inspection Program for managing aging of applicable components during the period of extended operation. Specifically, the applicant committed to perform at least one opportunistic or focused inspection of buried reinforced concrete piping and components and the buried stainless steel penetration bellows between the containment structure and the fuel handling building, including the penetration sleeves, within 10 years prior to the period of extended operation and within the first 10 years of the period of extended operation, and enhance the guidance for inspection of concrete aging effects.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Non-Steel Buried Piping Inspection 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).

3.0.3.3.5 Boral Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.2.5 describes the existing Boral Monitoring Program as plant-specific. The applicant stated that the Boral Monitoring Program manages the aging effects of the Boral neutron-absorbing material used in the Exxon and Holtec spent fuel storage rack assemblies in the Units 1 and 2 SFPs. The applicant also stated that reduction of neutron-absorbing capacity and loss of material are the AERMs. The applicant further stated that the program performs inspections and tests on Boral test coupons which simulate as nearly as possible the actual inservice properties of the Boral panels in the spent fuel storage rack assemblies. The applicant stated that the program calls for periodic examination of the test coupons, including visual inspections, weighing, and neutron attenuation testing, and the results of the evaluations are compared to the acceptance criteria for determination of any follow-up corrective action activities as appropriate. The applicant also stated that there are sufficient test coupons in the SFP to permit the inspection of the Boral test coupons beyond the period of extended operation for the Exxon and Holtec spent fuel storage rack assemblies.

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.

Scope of the Program. LRA Section B.2.2.5 states that the scope of the program includes monitoring of the Boral neutron-absorbing material in the spent fuel storage rack assemblies at Salem Units 1 and 2. The applicant stated that the program consists of a surveillance program which involves periodic inspections and testing of Boral test coupons that are monitored to ensure against unexpected degradation of the Boral neutron-absorbing material that are contained in the Units 1 and 2 spent fuel storage rack assemblies. The applicant further stated that the SFP has three high density Exxon Nuclear Corporation spent fuel storage rack assemblies in region I, and nine maximum density Holtec spent fuel storage rack assemblies in region II. The applicant stated that there are three types of Boral test coupons:

> There are two types of Boral test coupons utilized in the surveillance program for the Exxon spent fuel storage rack assemblies. [First test coupon] One type is a flat plate sandwich coupon. [Second test coupon] The other type is a short fuel Section that is a four sided cube prototype of the actual fuel cell. The flat plate sandwich coupons and short fuel sections are stainless steel clad Boral plate specimens that are of same materials and were produced by using the same manufacturing and Quality Assurance and Quality Control procedures specified for the spent fuel cells within the Exxon spent fuel storage rack assemblies. [Third test coupon] The Holtec Boral test coupons are each mounted in a stainless steel jacket simulating as nearly as possible the actual in-service geometry, physical mounting, materials, and flow conditions of the Boral in the spent fuel storage rack assemblies. The Boral is from the same production run as the Boral poison panels in the spent fuel storage rack assemblies. Each Boral test coupon is encased in a stainless steel jacket of the same alloy used in the manufacture of the spent fuel storage rack assemblies mounted with tolerance representative of those in the spent fuel storage rack assemblies.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the scope of the program should include the specific SCs of which the program manages the aging.

The staff confirmed that the "scope of the 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.2.2.5 states that the program is a condition monitoring program and does not include activities for prevention or mitigation of aging effects. The applicant stated that the program includes activities to periodically inspect for applicable aging effects. The applicant also stated that the Water Chemistry Program will be credited to manage loss of material of the aluminum cladding of the Boral.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state that for condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided.

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.

Parameters Monitored or Inspected. LRA Section B.2.2.5 states that the program performs inspections and tests on Boral test specimens or coupons. The physical properties of the Boral are monitored by performing measurements on representative Boral test coupons. The Boral test coupons are removed in accordance with a prescribed schedule. The applicant stated that the Boral test coupons representative of the Exxon spent fuel storage rack assemblies that are removed from the SFP are dried and weighed and the coupons undergo visual inspections, looking specifically for corrosion, weld cracks, or leaks. The applicant also stated that benchmark measurements of the coupons are not available from the initial fabrication of the coupons, prior to their placement in the SFP; as such, physical measurements (i.e., length, width, and thickness) are not performed as part of the surveillance inspection. The program will be enhanced to perform neutron attenuation testing of the coupons. After obtaining and recording the results of the inspections, the coupons are returned to the SFP. Unsatisfactory results are forwarded to the system engineer for evaluation and further action.

The applicant stated that the Boral test coupons representative of the Holtec spent fuel storage rack assemblies that are removed from the SFP undergo visual inspection, dimensional measurements, weight and specific gravity measurements, and neutron attenuation testing. After obtaining and recording the results of the inspections, the coupons are returned to the SFP. Unsatisfactory results are forwarded to the system engineer for evaluation and further action.

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 state that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s).

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.2.2.5 states that the program monitors changes in physical properties of the Boral by performing measurements on representative Boral test coupons. The applicant stated that the Boral test coupons simulate as nearly as possible the actual inservice geometry, physical mounting, materials, and flow conditions of the SFP water for the Boral poison panels in the spent fuel storage rack assemblies. The applicant also stated that each type of spent fuel storage rack assembly has representative test coupons, which are mounted on a specimen assembly or coupon tree suspended in a cell of the spent fuel storage rack assembly. The applicant further stated that the Exxon spent fuel storage rack assemblies have a specimen assembly of 50 Boral test coupons and the Holtec spent fuel storage rack assemblies have a specimen assembly with 10 Boral test coupons.

The applicant stated that every 2 years, 14 Exxon Boral test coupons are retrieved from the specimen assembly for inspections and examinations and returned to the SFP after completion of inspections. The applicant also stated that the specimen assembly location strategy ensures that the test coupons are placed next to a high burn-up assembly in the most recently discharged batch of spent fuel assemblies.

The applicant further stated that a Boral test coupon representative of the Holtec spent fuel storage rack assembly is removed every fifth refueling cycle going forward. The applicant also stated that the specimen assembly is located in a cell surrounded by eight of the most recently discharged fuel assemblies.

The applicant stated that the Boral test coupons representative of the Exxon spent fuel storage rack assemblies that are removed from the SFP are dried and weighed and undergo visual inspections, looking specifically for corrosion, weld cracks, or leaks. The applicant also stated that the inspections will be enhanced to include neutron attenuation testing. The applicant further stated that the Boral test coupons representative of the Holtec spent fuel storage rack assemblies that are removed from the SFP undergo visual inspection, dimensional measurements, weight and specific gravity measurements, and neutron attenuation testing.

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 state that detection of aging effects should occur before there is loss of the SC intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the SC intended function(s) 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, sample size, data collection, and timing of new or one-time inspections to ensure timely detection of aging effects. The program should provide information that links the parameters to be monitored or inspected to the aging effects being managed.

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.2.2.5 states that monitoring of the Boral neutron-absorbing material is accomplished by performing periodic examination of the Boral test coupons including parameters such as visual observations, dimensional measurements, weight and density determinations, and neutron attenuation testing. The applicant also stated that the results of the examinations are compared to values from pre-irradiated samples, when available, and previous examinations. The applicant further stated that results are evaluated against acceptance criteria for determination of any further corrective action activities as appropriate and the evaluation reports are maintained to provide a continuing source of data for trend analysis.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which state that monitoring and trending activities should be described and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. Plant-specific and industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency.

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.2.2.5 states that the acceptance criteria of the program for the Holtec spent fuel storage rack assemblies are as follows:

- A decrease of no more the 5 percent in Boron-10 content as determined by neutron attenuation measurements.
- An increase in thickness at any point should not exceed 10 percent of the initial thickness at that point.

The acceptance criteria of the program for the Exxon spent fuel storage rack assemblies are as follows:

- Percent Weight Change = [(Specimen Weight-Weight)/(Weight)] x 100%
- Allowable Percent Change = {4% + [(0.1%/yr) x # of yrs in Spent fuel Pool)]}

The applicant stated that the acceptance criteria for the Exxon spent fuel storage rack assemblies will be enhanced to include a decrease of no more than 5 percent in Boron-10 content as determined by neutron attenuation testing. The applicant also stated that the results are compared to archive values from pre-irradiated samples and with results from previous test coupon examinations, when available, summarized in reports of the surveillance and evaluated against acceptance criteria for determination of any follow-up corrective action activities as appropriate.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which state 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 program should include a methodology for analyzing the results against applicable acceptance criteria.

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.

Operating Experience. LRA Section B.2.2.5 summarizes operating experience related to the Boral Monitoring Program. The applicant provided the following examples of operating experience to demonstrate that the effects of aging are being adequately managed:

(1) The applicant stated that in 2006, during the performance of the Boral test coupon surveillance of the representative Boral test coupons of the Unit 2 Exxon spent fuel storage rack assemblies, a small corrosion mark which was brownish in color, very small (approximately 0.25 inches in diameter), and the washout trail extended approximately 1 inch down the side of the test coupon was discovered. The applicant also stated that this anomaly was documented in a corrective action report and that the evaluation concluded that this did not represent degradation to the intended function of the Boral neutron-absorbing material of the Exxon spent fuel storage rack assemblies. The applicant further stated that this corrective action report will provide data for trending of inspection results for the Boral Monitoring Program.

(2) The applicant stated that in 2003, industry operating experience OE21287 was evaluated for potential generic implication at Salem. The applicant also stated that a brief summary of the operating experience was that during the inspection of a Boral test coupon (and two additional coupons as part of the extent of condition) that had been removed from the plant's SFP, an abnormality was noted in which visual inspection of the one Boral test coupon indicated bulging of the Boral aluminum, cladding that normally encapsulates, and is adhered to, the internal Boron carbide and aluminum composite layer. The applicant further stated that the structural integrity of the clad material had been affected but there has been no evidence of loss or redistribution of the boron carbide in the active poison layer of the Boral material at the time and the inspection yielded no apparent loss of neutron-absorbing material. The applicant stated that the operating experience report and subsequent 10 CFR Part 21 notification concerning bulging and blistering of a Boral test coupon has had no plant-specific impact on the test coupon surveillance program and that there has been no evidence of bulging or blistering noted during past inspections.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which state that operating experience with existing programs should be discussed. The operating experience of AMPs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the 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 operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental 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.2.2.5 provides the UFSAR supplement for the Boral Monitoring Program. The staff reviewed this UFSAR supplement description of the program and has determined that it is acceptable.

The staff also notes that the applicant committed (Commitment No. 45) to ongoing implementation of the existing Boral Monitoring Program for managing aging of applicable components during the period of extended operation. Particularly, the applicant committed to enhance the program prior to the period of extended operation. The applicant committed to:

(1) Perform a neutron attenuation measurement on each of the three (no vent holes, one vent holes, and two vent holes) flat plate sandwich Boral test coupons during the first three 2-year inspection frequency periods and every 6 years thereafter for the Exxon spent fuel storage rack assemblies.

(2) Include acceptance criteria of the neutron attenuation measurement on the Boral test coupons for the Exxon spent fuel storage rack assemblies: A decrease of no more the 5 percent in Boron-10 content as determined by neutron attenuation measurements. The benchmark Boron-10 content used for comparison will be based on the nominal Boron-10 areal density in the design specification.

The staff reviewed the enhancements and determined that they are acceptable because neutron attenuation testing has been determined to be one acceptable means to monitor for loss of material and loss of neutron-absorbing capability in SFPs during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Boral Monitoring 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).

3.0.3.3.6 Nickel Alloy Aging Management

Summary of Technical Information in the Application. LRA Section B.2.2.6 describes the Nickel Alloy Aging Management Program as an existing program. The applicant stated that the Nickel Alloy Aging Management Program manages cracking in a reactor coolant environment. The applicant also stated that the Nickel Alloy Aging Management Program is both a mitigative and a condition monitoring program. The applicant stated that mitigative actions include replacement of components whose materials are susceptible to cracking and MSIP. The applicant stated that condition monitoring actions include surface examinations, volumetric examinations, and bare metal visual examinations to detect cracking.

Staff Evaluation. The staff reviewed program elements 1 through 6 and 10 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.

GALL Report Table 3.1-1, ID 31 and further evaluation paragraph 3.1.2.2.13 state that the applicant should "provide a commitment in the UFSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff accepted industry guidelines." The staff notes that such a commitment is not specifically provided in the list of commitments contained in the UFSAR supplement. The list of commitments does, however, contain a commitment to implement the Nickel Alloy Aging Management Program as a whole (Commitment No. 46). The staff also notes that the program (program description section) and the UFSAR supplement description of the program state, "The Nickel Alloy Aging Management program implements applicable NRC Bulletins, Generic Letters and staff-accepted industry guidelines." The staff further notes that LRA Section 3.1.2.2.13 states, "Salem complies with applicable NRC Orders and provides a commitment in the UFSAR Supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines." The staff considers these statements to be an adequate indication that the applicant has made the commitment described in the GALL Report because the applicant has committed to its overall Nickel Alloy Aging Management Program and because the program and its descriptions contain statements indicating that the program implements NRC bulletins, GLs, and staff-accepted industry guidelines.

Scope of the Program. LRA Section B.2.2.6 states that the Nickel Alloy Aging Management Program manages the cracking of Alloy 600 components. A specific list of components which are, and are not, included in this program is provided.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the program should include the specific SCs for which the program manages aging.

Based on the exhaustive list provided, which addresses materials and components included within the scope of the AMP, the staff confirmed that the "scope of the 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.2.2.6 states that the Nickel Alloy Aging Management Program includes mitigation activities and strategies to ensure the operability of nickel-alloy components. This Section cites the MSIP and replacement of Alloy 600/82/182 materials with 690/52/152 materials as two examples of 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 state that activities for prevention and mitigation programs should be described.

Based on the description of the available mitigative techniques, 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.

Parameters Monitored or Inspected. LRA Section B.2.2.6 states that the program monitors for cracking due to SCC through a combination of bare metal visual, surface, and volumetric exams. This Section also states that the components susceptible to cracking are itemized in a database and are subject either to an augmented inspection program or mitigation.

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 state that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s) and for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff finds that, for the components under consideration, cracking is the degradation mechanism which will affect their intended function and that a combination of visual, surface, and volumetric exams will be capable of detecting cracks. Based on this finding, 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.2.2.6 states that bare metal visual, surface, and volumetric exams are used to detect cracking due to SCC in Alloy 600 components. This Section also states that inspection requirements, including frequencies, are contained in ASME Code Section XI and in Code Case N-722.

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 state that detection of aging effects should occur before there is a loss of the SC intended function(s). The criteria also state that parameters to be monitored or inspected should be appropriate to ensure that the SC intended function will be adequately maintained for license renewal under all CLB design conditions. The criteria further state that a program based solely on detecting SC failure should not be considered as an effective AMP for license renewal. The criteria state that this program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program). The criteria continue by stating that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

In its review, the staff determined that cracking is an appropriate parameter to monitor to ensure the maintenance of intended function of the components under consideration. The staff also determined that a combination of bare metal visual, surface, and volumetric test methods were capable of detecting aging prior to loss of intended function. The staff further determined that this element of the AMP refers to the CFR, the ASME Code, and various code cases and that the specifications (how, where, when) for these inspections are contained in these documents. The staff finally determined that there is no industry or plant-specific operating experience which necessitates deviating from the inspections proposed in this program element.

Based on the above evaluation, 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.2.2.6 states that crack dimensions are monitored and trended as part of this program. This Section also states that ASME Code Section XI, Code Case N-722, and MRP-139 are used to determine inspection techniques and frequencies. This section further states that all flaws are evaluated and dispositioned in accordance with ASME

Code Section XI, Subsection IWB-3500. This section finally states that industry operating experience is monitored and incorporated, as necessary, into this AMP.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which state that monitoring and trending activities should be described and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. The criteria also state that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The criteria further state that this program element describes "how" the data collected are evaluated and may also include trending for a forward look, including an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection will occur before a loss of SC intended function.

In this review, the staff determined that this program element adequately describes the monitoring and trending which is proposed. The staff also determined that the governing documents for the inspections to be monitored and trended provide sufficient guidance to provide timely corrective action prior to loss of intended function. This guidance includes information concerning inspection frequency and the modification of that frequency-based plant-specific or industry operating experience. The staff further determined that the program element and the governing documents provide sufficient guidance to allow collected data to be compared to applicable acceptance standards.

Based on the above evaluation, 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.2.2.6 states that acceptance criteria for this program are contained in governing documents (ASME Code Section XI, Subsection IWB 3640 and WCAP-15657-P). This Section also states that inspection results are dispositioned as being acceptable to permit continued operation or corrective action is initiated.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which state the acceptance criteria of the program and its basis should be described, including ensuring that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. Acceptance criteria could be specific numerical values or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited. The criteria also state that acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads. The criteria further state that qualitative inspections should be performed to same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site-specific programs.

In its review, the staff determined that the acceptance criteria for these inspections are clearly defined in the program element or in the governing documents. The staff also has no reason to believe that these values, many of which carry the force of regulation, would not allow for the intended function of the components under consideration to be maintained during the period of extended operation under all CLB design loads.

Based on the above review, 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.

Operating Experience. LRA Section B.2.2.6 summarizes operating experience related to the Nickel Alloy Aging Management Program. In this program element, the applicant provided a detailed list of components which have been inspected. These inspections resulted in no flaws being found, the component being proactively replaced, or the component being subjected to mechanical stress improvement.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which state that the operating experience information provided should provide objective evidence that the effects of aging will be adequately managed so that the intended function(s) of the in-scope SCs are maintained during the period of extended operation.

In its review, the staff noted that the applicant responded to the potential for cracks or the discovery of cracks in a number of different ways. In each case, the staff considers the approach used to be appropriate for the circumstances. The staff views this variability in approach as indicting that the applicant’s AMP is an effective tool in identifying and responding to cracking or the threat of cracking of nickel alloys.

Based on its review, the staff finds that operating experience related to the applicant’s program demonstrates that it can adequately manage the detrimental 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.2.2.6 provides the UFSAR supplement for the Nickel Alloy Aging Management Program. The staff reviewed this UFSAR supplement description of the program and notes that it provides an adequate description of the program.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion*.* On the basis of its technical review of the applicant’s Nickel Alloy Aging Management Program, the staff concludes that the applicant has demonstrated that, through the use of this AMP, the effects of aging of nickel alloys may be adequately managed so that the intended function(s) of the components under consideration will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in Application

In LRA Appendix A, "Final Safety Analysis Report Supplement," Section A.1.5, "Quality Assurance Program and Administrative Controls," and Appendix B, "Aging Management Programs," Section B.1.3, "Quality Assurance Program and Administrative Controls," the applicant described the elements of corrective actions, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components. The Salem quality assurance program (QAP) is used which includes the elements of corrective actions, confirmation process, and administrative controls. Corrective actions, confirmation process, and administrative controls are applied in accordance with the QAP regardless of the safety classification of the components. LRA Appendix A, Section A.1.5 and Appendix B, Section B.1.3 state that the QAP implements the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and is consistent with the SRP-LR, Revision 1.

3.0.4.2 Staff Evaluation

Pursuant to 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. The SRP-LR, Branch Technical Position RLSB-1, "Aging Management Review-Generic," describes 10 attributes of an acceptable AMP. Three of these ten attributes are associated with the quality assurance (QA) activities of corrective actions, confirmation process, and administrative controls. Table A.1-1, "Elements of an Aging Management Program for License Renewal," of Branch Technical Position RLSB-1 provides the following description of these quality attributes:

(1) Attribute No. 7 - Corrective actions, including root cause determination and prevention of recurrence, should be timely.

(2) Attribute No. 8 - Confirmation process, which should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(3) Attribute No. 9 - Administrative controls, which should provide a formal review and approval process.

The SRP-LR, Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs," states that those aspects of the AMP that affect quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the applicant's existing 10 CFR Part 50, Appendix B QAP may be used to address the elements of corrective actions, confirmation process, and administrative controls. Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

> Safety-related SCs are subject to Appendix B to 10 CFR Part 50 requirements which are adequate to address all quality related aspects of an AMP consistent with the CLB of the facility for the period of extended operation. For nonsafety-related SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its Appendix B to 10 CFR Part 50

program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the Final Safety Analysis Report supplement in accordance with 10 CFR 54.21(d).

The staff reviewed the applicant's AMPs described in LRA Appendix A and Appendix B and the associated implementing procedures. The purpose of this review was to ensure that the QA attributes (corrective actions, confirmation process, and administrative controls) were consistent with the staff's guidance described in Branch Technical Position IQMB-1. Based on the staff's evaluation, the descriptions of the AMPs and their associated quality attributes provided in LRA Appendix A, Section A.1.5 and Appendix B, Section B.1.3 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 Appendix A, Section A.1.5 and Appendix B, Section B.1.3 were determined to be consistent with the staff's position regarding QA for aging management. The staff concludes that the QA attributes (corrective actions, confirmation process, and administrative controls) of the applicant's AMPs are consistent with 10 CFR 54.21(a)(3).

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, reactor vessel internals, and RCS components and component groups of the following:

- reactor coolant system
- reactor vessel
- reactor vessel internals
- steam generator

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the RCS, reactor vessel, reactor vessel internals, and SG. LRA Table 3.1.1, "Summary of Aging Management Evaluations for the Reactor Vessel, Internals and Reactor Coolant System," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the RCS, reactor vessel, reactor vessel internals, and SG 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 issue 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 RCS, reactor vessel, reactor vessel internals, and SG components within the scope of license renewal and subject to an AMR 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 conducted an onsite audit of the applicant's AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified 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 had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.1.2.1 and 3.1.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.1.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line 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 (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads, and welds (3.1.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy RCPB piping, piping components, and piping elements exposed to reactor coolant (3.1.1-3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pump and valve closure bolting (3.1.1-4)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) check Code limits for allowable cycles (< 7,000 cycles) of thermal stress range	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Stainless steel and nickel-alloy reactor vessel internals components (3.1.1-5)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.1.2.2.1)
Nickel-alloy tubes and sleeves in a reactor coolant and secondary feedwater/steam environment (3.1.1-6)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.1.2.2.1)
Steel and stainless steel RCPB closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, steam generator components, piping and components external surfaces and bolting (3.1.1-7)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.1.2.2.1)
Steel; stainless steel; and nickel-alloy RCPB piping, piping components, piping elements; flanges; nozzles and safe ends; pressurizer vessel shell heads and welds; heater sheaths and sleeves; penetrations; and thermal sleeves (3.1.1-8)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor vessel components: flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads, and welds (3.1.1-9)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy steam generator components (flanges; penetrations; nozzles; safe ends, lower heads, and welds) (3.1.1-10)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.1.2.2.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or reactor core isolation cooling, and spare) exposed to reactor coolant (3.1.1-11)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2)
Steel steam generator shell assembly exposed to secondary feedwater and steam (3.1.1-12)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and Steam Generator Tube Integrity	Consistent with the GALL Report (see SER Section 3.1.2.2.2(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-13)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(2))
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 (3.1.1-14)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(3))
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy RCPB components exposed to reactor coolant (3.1.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(3))
Steel steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam (3.1.1-16)	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and, for Westinghouse Model 44 and 51 S/G, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed.	Yes	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and Steam Generator Tube Integrity	Consistent with the GALL Report (see SER Section 3.1.2.2.2(4))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds (3.1.1-17)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with 10 CFR Part 50, Appendix G 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	Loss of fracture toughness due to neutron irradiation embrittlement is a TLAA (see SER Section 3.1.2.2.3(1))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-18)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Yes	Reactor Vessel Surveillance	Consistent with the GALL Report (see SER Section 3.1.2.2.3(2))
Stainless steel and nickel-alloy top head enclosure vessel flange leak detection line (3.1.1-19)	Cracking due to SCC and intergranular stress-corrosion cracking (IGSCC)	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-20)	Cracking due to SCC and IGSCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (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 (3.1.1-21)	Crack growth due to cyclic loading	TLAA	Yes	Not applicable	Not applicable to Salem (see SER Section 3.1.2.2.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy reactor vessel internals components exposed to reactor coolant and neutron flux (3.1.1-22)	Loss of fracture toughness due to neutron irradiation embrittlement, void swelling	UFSAR supplement commitment to: (1) participate in industry reactor vessel internals AMPs, (2) implement applicable results, (3) submit for NRC approval > 24 months before the period of extended operation a reactor vessel internals inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.2.6)
Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument (BMI) guide tubes (3.1.1-23)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report (see SER Section 3.1.2.2.7(1))
CASS Class 1 piping, piping components, and piping elements exposed to reactor coolant (3.1.1-24)	Cracking due to SCC	Water Chemistry and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific AMP	Yes	Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report (see SER Section 3.1.2.2.7(2))
Stainless steel jet pump sensing line (3.1.1-25)	Cracking due to cyclic loading	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.8(1))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-26)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.8(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy reactor vessel internals screws, bolts, tie rods, and hold-down springs (3.1.1-27)	Loss of preload due to stress relaxation	UFSAR supplement commitment to: (1) participate in industry reactor vessel internals AMPs, (2) implement applicable results, (3) submit for NRC approval > 24 months before the period of extended operation a reactor vessel internals inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.2.9)
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-28)	Loss of material due to erosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.1.2.2.10)
Stainless steel steam dryers exposed to reactor coolant (3.1.1-29)	Cracking due to flow-induced vibration	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.11)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel reactor vessel internals components (e.g., upper internals assembly, rod cluster control assembly (RCCA) guide tube assemblies, baffle/former assembly, lower internal assembly, shroud assemblies, plenum cover and plenum cylinder, upper grid assembly, control rod guide tube assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly, thermal shield, instrumentation support structures) (3.1.1-30)	Cracking due to SCC and IASCC	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry reactor vessel internals AMPs, (2) implement applicable results, (3) submit for NRC approval < 24 months before the period of extended operation a reactor vessel internals inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	PWR Vessel Internals and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.12)
Nickel alloy and steel with nickel-alloy cladding piping, piping component, piping elements, penetrations, nozzles, safe ends, and welds (other than reactor vessel head); pressurizer heater sheaths, sleeves, diaphragm plate, manways and flanges; core support pads/core guide lugs (3.1.1-31)	Cracking due to PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and UFSAR supplement commitment to implement applicable plant commitments to: (1) NRC orders, bulletins, and GLs associated with nickel alloys and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Nickel Alloy Aging Management; and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.13)
Steel steam generator feedwater inlet ring and supports (3.1.1-32)	Wall thinning due to flow-accelerated corrosion	A plant-specific AMP is to be evaluated.	Yes	Steam Generator Tube Integrity	Consistent with the GALL Report (see SER Section 3.1.2.2.14)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy reactor vessel internals components (3.1.1-33)	Changes in dimensions due to void swelling	UFSAR supplement commitment to: (1) participate in industry reactor vessel internals AMPs, (2) implement applicable results, (3) submit for NRC approval > 24 months before the period of extended operation a reactor vessel internals inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.2.15)
Stainless steel and nickel-alloy reactor control rod drive (CRD) head penetration pressure housings (3.1.1-34)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC orders and provide a commitment in the UFSAR supplement to implement applicable: (1) bulletins and GLs and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.16(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel with stainless steel or nickel-alloy cladding primary-side components; steam generator upper and lower heads, tubesheets and tube-to-tubesheet welds (3.1.1-35)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC orders and provide a commitment in the UFSAR supplement to implement applicable: (1) bulletins and GLs and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Applicable to once-through steam generators (OTSGs), therefore, not applicable to Salem, except for tube-to-tubesheet welds between nickel-alloy cladding and nickel-alloy tubes in the SG	Consistent with the GALL Report (see SER Section 3.1.2.2.16(1))
Nickel-alloy, stainless steel pressurizer spray head (3.1.1-36)	Cracking due to SCC and PWSCC	Water Chemistry and One-Time Inspection and, for nickel-alloy welded spray heads, comply with applicable NRC orders and provide a commitment in the UFSAR supplement to implement applicable: (1) bulletins and GLs and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.16(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy reactor vessel internals components (e.g., upper internals assembly, RCCA guide tube assemblies, lower internal assembly, control element assembly (CEA) shroud assemblies, core shroud assembly, core support shield assembly, core barrel assembly, lower grid assembly, and flow distributor assembly) (3.1.1-37)	Cracking due to SCC, PWSCC, and IASCC	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry reactor vessel internals AMPs, (2) implement applicable results, (3) submit for NRC approval > 24 months before the period of extended operation a reactor vessel internals inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	PWR Vessel Internals and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.17)
Steel (with or without stainless steel cladding) CRD return line nozzles exposed to reactor coolant (3.1.1-38)	Cracking due to cyclic loading	BWR Control Rod Drive Return Line Nozzle	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-39)	Cracking due to cyclic loading	BWR Feedwater Nozzle	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel-alloy penetrations for CRD stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant (3.1.1-40)	Cracking due to SCC, IGSCC, and cyclic loading	BWR Penetrations and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy piping, piping components, and piping elements ≥ 4″ NPS; nozzle safe ends and associated welds (3.1.1-41)	Cracking due to SCC and IGSCC	BWR Stress Corrosion Cracking and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel-alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-42)	Cracking due to SCC and IGSCC	BWR Vessel ID Attachment Welds and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel fuel supports and CRD assemblies CRD housing exposed to reactor coolant (3.1.1-43)	Cracking due to SCC and IGSCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel-alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, CRD housing, and nuclear instrumentation guide tubes (3.1.1-44)	Cracking due to SCC, IGSCC, and IASCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-45)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Nickel-alloy core shroud and core plate access hole cover (mechanical covers) (3.1.1-46)	Cracking due to SCC, IGSCC, and IASCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy reactor vessel internals exposed to reactor coolant (3.1.1-47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel Class 1 piping, fittings, and branch connections < 4″ NPS exposed to reactor coolant (3.1.1-48)	Cracking due to SCC, IGSCC (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Nickel-alloy core shroud and core plate access hole cover (welded covers) (3.1.1-49)	Cracking due to SCC, IGSCC, and IASCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for boiling-water reactors (BWRs) with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
High-strength, low-alloy steel top head closure studs and nuts exposed to air with reactor coolant leakage (3.1.1-50)	Cracking due to SCC and IGSCC	Reactor Head Closure Studs	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
CASS jet pump assembly castings; orificed fuel support (3.1.1-51)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel RCPB pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems (3.1.1-52)	Cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.1.2.1.2)
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.1.1-53)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.1.1-54)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)
CASS Class 1 pump casings and valve bodies and bonnets exposed to reactor coolant > 250 °C (482 °F) (3.1.1-55)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection (IWB, IWC, and IWD). Thermal aging susceptibility screening is not necessary, ISI requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings.	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report (see SER Section 3.1.2.1.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy > 15% zinc (Zn) piping, piping components, and piping elements exposed to closed-cycle cooling water (3.1.1-56)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)
CASS Class 1 piping, piping components, and piping elements and CRD pressure housings exposed to reactor coolant > 250 °C (482 °F) (3.1.1-57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Thermal Aging Embrittlement of CASS	Consistent with the GALL Report
Steel RCPB external surfaces exposed to air with borated water leakage (3.1.1-58)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, auxiliary feedwater nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-59)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
Stainless steel flux thimble tubes (with or without chrome plating) (3.1.1-60)	Loss of material due to wear	Flux Thimble Tube Inspection	No	Flux Thimble Tube Inspection	Consistent with the GALL Report
Stainless steel, steel pressurizer integral support exposed to air with metal temperature up to 288 °C (550 °F) (3.1.1-61)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel with stainless steel cladding RCS cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-62)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report
Steel reactor vessel flange, stainless steel and nickel-alloy reactor vessel internals exposed to reactor coolant (e.g., upper and lower internals assembly, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, and lower grid assembly) (3.1.1-63)	Loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD)	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report
Stainless steel and steel with stainless steel or nickel-alloy cladding pressurizer components (3.1.1-64)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Nickel-alloy reactor vessel upper head and CRD penetration nozzles, instrument tubes, head vent pipe (top head), and welds (3.1.1-65)	Cracking due to PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors; and Water Chemistry	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam (3.1.1-66)	Loss of material due to erosion	Inservice Inspection (IWB, IWC, and IWD) for Class 2 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.1)
Steel with stainless steel or nickel-alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-67)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, RCS cold leg, hot leg, surge line, and spray line piping and fittings (3.1.1-68)	Cracking due to SCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Stainless steel, nickel-alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant (3.1.1-69)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel; steel with stainless steel cladding Class 1 piping, fittings, and branch connections < 4″ NPS exposed to reactor coolant (3.1.1-70)	Cracking due to SCC and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	Consistent with the GALL Report
High-strength, low-alloy steel closure head stud assembly exposed to air with reactor coolant leakage (3.1.1-71)	Cracking due to SCC; loss of material due to wear	Reactor Head Closure Studs	No	Reactor Head Closure Studs	Consistent with the GALL Report
Nickel-alloy steam generator tubes and sleeves exposed to secondary feedwater/steam (3.1.1-72)	Cracking due to outside-diameter stress-corrosion cracking (ODSCC) and intergranular attack, loss of material due to fretting and wear	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Water Chemistry	Consistent with the GALL Report
Nickel-alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-73)	Cracking due to PWSCC	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Water Chemistry	Consistent with the GALL Report
Chrome plated steel, stainless steel, nickel-alloy steam generator anti-vibration bars exposed to secondary feedwater/steam (3.1.1-74)	Cracking due to SCC, loss of material due to crevice corrosion and fretting	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Water Chemistry	Consistent with the GALL Report
Nickel-alloy OTSG tubes exposed to secondary feedwater/steam (3.1.1-75)	Denting due to corrosion of carbon steel tube support plate	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator tube support plate, tube bundle wrapper exposed to secondary feedwater/steam (3.1.1-76)	Loss of material due to erosion, general, pitting, and crevice corrosion, ligament cracking due to corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Water Chemistry	Consistent with the GALL Report
Nickel-alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater/steam (3.1.1-77)	Loss of material due to wastage and pitting corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)
Steel steam generator tube support lattice bars exposed to secondary feedwater/steam (3.1.1-78)	Wall thinning due to flow-accelerated corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)
Nickel-alloy steam generator tubes exposed to secondary feedwater/steam (3.1.1-79)	Denting due to corrosion of steel tube support plate	Steam Generator Tube Integrity, Water Chemistry and, for plants that could experience denting at the upper support plates, evaluate potential for rapidly propagating cracks and then develop and take corrective actions consistent with NRC Bulletin 88-02.	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
CASS reactor vessel internals (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, control rod guide tube assembly, core support shield assembly, and lower grid assembly) (3.1.1-80)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.1.4)
Nickel alloy or nickel-alloy clad steam generator divider plate exposed to reactor coolant (3.1.1-81)	Cracking due to PWSCC	Water Chemistry	No	Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.5)
Stainless steel steam generator primary-side divider plate exposed to reactor coolant (3.1.1-82)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor vessel internals and RCPB components exposed to reactor coolant (3.1.1-83)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry	Consistent with the GALL Report
Nickel-alloy steam generator components such as secondary-side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/steam (3.1.1-84)	Cracking due to SCC	Water Chemistry and One-Time Inspection or Inservice Inspection (IWB, IWC, and IWD)	No	Not applicable	Not applicable to Salem (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.1.1-85)	None	None	NA	None	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (external); air with borated water leakage; concrete; gas (3.1.1-86)	None	None	NA	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements in concrete (3.1.1-87)	None	None	NA	None	Not applicable to Salem (see SER Section 3.1.2.1.1)

The staff's review of the RCS component groups followed several approaches. One approach, documented in SER Section 3.1.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.1.2.2, discusses the staff's review of AMR results for components 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, discusses the staff's review of AMR results for components 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 RCS components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the reactor vessel, reactor vessel internals, and RCS components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion

- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Flux Thimble Tube Inspection
- Lubricating Oil Analysis
- Nickel Alloy Aging Management Program
- Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Periodic Inspection
- PWR Vessel Internals
- Reactor Head Closure Studs
- Reactor Vessel Surveillance
- Steam Generator Tube Integrity
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)
- TLAA
- Water Chemistry

LRA Tables 3.1.2-1 through 3.1.2-4 summarize the results of AMRs for the RCS, reactor vessel, reactor vessel internal, and SG components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line 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 reviewed these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

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

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

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

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, it did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the RCS, reactor vessel, reactor vessel internals, and SG components that are subject to an AMR.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.1.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

3.1.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.1.1, item 3.1.1-38–51 discusses the applicant's determination on GALL Report AMR line items that are applicable only to BWR-designed reactors. In the applicant's AMR discussions for items 38–51, no additional information is provided. The staff confirmed that AMR items 38–51, in Table 1 of the GALL Report, Volume 1 are only applicable to BWR-designed reactors and that Salem is a PWR. Based on this determination, the staff finds that the applicant has provided an acceptable basis for concluding AMR items 38–51 in Table 1 of the GALL Report, Volume 1 are not applicable to Salem.

LRA Table 3.1.1, item 3.1.1-53 addresses steel piping, piping components, and piping elements exposed to closed-cycle cooling water subject to loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this line item is not applicable because it has no in-scope steel piping, piping components, or piping elements exposed to closed-cycle cooling water in the RCS, so the applicable GALL Report line item was not used. The staff reviewed the applicant’s UFSAR and confirmed that no in-scope steel piping, piping components, and piping elements exposed to closed-cycle cooling water are present in these systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.1.1, item 3.1.1-54 addresses copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water subject to loss of material due to pitting, crevice, and galvanic corrosion for this component group. The applicant stated that this line item is not applicable because it has no in-scope copper alloy piping, piping components, or piping elements exposed to closed-cycle cooling water in the reactor vessel, internals, and RCS, so the applicable GALL Report line item was not used. The staff reviewed the applicant’s UFSAR and confirmed that no in-scope copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water are present in these systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.1.1, item 3.1.1-56 addresses copper alloy greater than 15 percent Zn piping, piping components, and piping elements exposed to closed-cycle cooling water subject to loss of material due to selective leaching for this component group. The applicant stated that this line item is not applicable because it has no in-scope copper alloy greater than 15 percent Zn components exposed to closed-cycle cooling water in the reactor vessel, internals, and RCS, so the applicable GALL Report line item was not used. The staff reviewed the applicant’s UFSAR and confirmed that no in-scope copper alloy greater than 15 percent Zn piping, piping components, and piping elements exposed to closed-cycle cooling water are present in these systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.1.1, item 3.1.1-66 addresses steel SG secondary manways and handholds, cover only exposed to air with leaking secondary-side water and/or steam subject to loss of material due to erosion for this component group. The applicant stated that this line item is not applicable because these components are not exposed to air with leaking secondary-side water and/or steam since there has been no operating experience at its plant with leaking manways or handholes.

The staff noted that even if the applicant had not observed any operating experience of leaking manways or handholes, this does not indicate that this Material, Environment, Aging Effect/Mechanism, and Aging Management Program (MEAP) combination can be excluded for these components during the period of extended operation. The staff determined that the applicant did not provide sufficient information to justify that LRA Table 3.1.1, item 3.1.1-66 is not applicable.

By letter dated July 30, 2010, the staff issued RAI 3.1.1.66-01, requesting that the applicant demonstrate how the aging effect of loss of material due to erosion for steel SG secondary manways, cover only exposed to air with leaking secondary-side water and/or steam will never occur during the period of extended operation, or revise accordingly its proposed LRA Table 3.1.1, item 3.1.1-66.

In its response dated August 26, 2010, the applicant stated that it agreed with the staff that the aging effect of loss of material due to erosion for steel SG secondary manways, cover only, exposed to air with leaking secondary side water and/or steam may occur during the period of extended operation. The applicant further stated that this aging effect and mechanism also applies to the component type "SGs (Inspection Ports and Diaphragm, Handholes and Covers)" for the hand-hole covers only since they are also constructed of steel and are potentially exposed to the environment of air with leaking secondary-side water and/or steam. Consequently, the applicant revised LRA Table 3.1.1, item 3.1.1-66 by identifying this item as consistent with the GALL Report and stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to manage loss of material due to erosion for the steel SG secondary manway and handhole covers exposed to air with leaking secondary-side water and/or steam. The applicant also indicated that LRA Table 3.1.1, item 3.1.1-66, pertains to the OTSGs, whereas its SGs are recirculating SGs. The staff noted that this item appears only in the GALL Report, Revision 1, Volume 2, Table IV.D2 for OTSGs; however, the staff noted that it does not preclude the associated aging effect from being applicable to a component with a similar material/environment/aging effect and mechanism combination in recirculating SGs.

The staff reviewed the applicant's response to RAI 3.1.1.66-01 and finds it not acceptable because the staff noted that in the revised LRA Table 3.1.2-4, SG inspection ports and diaphragm, handholes, and covers are described as being fabricated of carbon or low-alloy steel with stainless steel cladding, whereas in the text of its response, the applicant described this component as constructed of steel, at least for the covers.

In a conference call on September 9, 2010, to discuss and clarify the applicant's response, the applicant agreed to revise LRA Table 3.1.2-4 and change the material to low-alloy steel, consistent with the text in response to RAI 3.1.1.66-01.

In a letter dated October 8, 2010, the applicant clarified that, although the component SG inspection ports and diaphragm, handholes, and covers does not have the material "carbon or low alloy steel with stainless steel cladding," it contains both low-alloy steel and stainless steel. The staff noted that in order to provide distinction between the materials, the applicant separated this component into two components: SG inspection ports, handholes, and covers and SG inspection port diaphragm. The applicant revised the material for the component SG inspection ports, handholes, and covers from "carbon or low alloy steel with stainless steel cladding" to "low alloy steel," and included the component SG inspection port diaphragm constructed of stainless steel that only applies to the Unit 2 SGs. The staff noted that as result of the revision described above, the applicant revised the aging effect of loss of material due to pitting and crevice corrosion with loss of material due to general, pitting, and crevice corrosion. Consistent with the AMR items in the GALL Report for SGs, the applicant revised LRA Table 3.1.2-4 to refer to GALL item IV.D1-12 instead of VIII.F-23 for this component and stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to manage the aging effect of loss of material due to general, pitting, and crevice corrosion, in complement with the Water Chemistry Program. As a result of adding the aging effect of loss of material due to erosion for the SG inspection ports, handholes, and covers and SG secondary manways and covers, consistent with other component types in LRA Table 3.1.2-4, the applicant revised the generic note "A" with a generic note "C." The applicant updated LRA Table 2.3.1-4 to reflect the separation between SG inspection ports, handholes, and covers and the Unit 2 SG inspection port diaphragm. The applicant revised LRA Table 3.1.1, item 3.1.1-16 and LRA Section 3.1.2.2.2.2 to include the SG low-alloy steel inspection ports, handholes, and covers exposed to treated water to be managed for loss of material due to general, pitting, and crevice corrosion. It also revised LRA Table 3.1.2-4 to clarify that the SG stainless steel inspection port diaphragm is applicable to only Unit 2 SGs. The applicant revised LRA Table 3.4.1, item 3.4.1-14 and LRA Section 3.4.2.2.6 to include the Unit 2 SG stainless steel inspection port diaphragm exposed to treated water to be managed for cracking due to SCC. The applicant also revised LRA Table 3.4.1, item 3.4.1-16 and LRA Section 3.4.2.2.7.1 to include this component to be managed for loss of material due to pitting and crevice corrosion. In LRA Table 3.4.1, items 3.4.1-14 and 3.4.1-16, the applicant stated that components in the SGs have been aligned to these item numbers based on material, environment, and aging effect and that the Steam Generator Tube Integrity Program will be substituted to verify the effectiveness of the Water Chemistry Program to manage cracking due to SCC and the loss of material due to pitting and crevice corrosion, respectively, in the Unit 2 SG stainless steel inspection port diaphragm exposed to treated water greater than 60 °C (140 °F). In addition, the applicant stated that since the stainless steel cladding is no longer valid for the SG inspection ports, handholes, and covers, the corresponding aging effect of cracking due to SCC of stainless steel in the environment of treated water greater than 60 °C (140 °F) is no longer applicable and was deleted from LRA Table 3.1.2-4.

Based on its review, the staff finds the applicant's response to RAI 3.1.1.66-01 acceptable because the applicant has revised the LRA sections related to its SGs in order to include the appropriate components for which it identified the adequate aging effects and AMPs and revised the plant-specific notes. The staff's evaluations of the applicant's revisions to LRA Sections 3.1.2.2.2.2, 3.4.2.2.6, and 3.4.2.2.7.1; LRA Table 3.1.1, item 3.1.1-16; and LRA Table 3.4.1, items 3.4.1-14 and 3.4.1-16 are documented in SER Sections 3.1.2.2.2.2, 3.4.2.2.6, and 3.4.2.2.7.1, respectively. The staff's concern described in RAI 3.1.1.66-01 is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.1.1, item 3.1.1-75 addresses nickel-alloy OTSG tubes exposed to secondary feedwater/steam subject to denting due to corrosion of the carbon steel tube support plate for this component group. The applicant stated that this line item is not applicable because it does not have OTSGs, so the applicable GALL Report line item was not used. The staff noted that item 3.1.1-75 references GALL AMR item IV.D2-13, which is applicable to OTSGs. The staff reviewed the applicant's UFSAR Section 5.1, Figures 5.1-3 and 5.1-3A and confirmed that the applicant's SGs for both units are recirculating SGs and, therefore, finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-77 addresses nickel-alloy SG tubes and sleeves exposed to phosphate chemistry in secondary feedwater/steam subject to loss of material due to wastage and pitting corrosion for this component group. The applicant stated that this line item is not applicable because the applicant does not use phosphate chemistry in secondary feedwater or steam, so the applicable GALL Report line item was not used. The staff reviewed UFSAR Section 10.3.5.2 and confirmed that the applicant does not operate on phosphate chemistry in the secondary side and, therefore, finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-78 addresses steel SG tube support lattice bars exposed to secondary feedwater/steam subject to wall thinning due to flow-accelerated corrosion for this component group. The applicant stated that this line item is not applicable because its SGs do not contain lattice bars, so the applicable GALL Report line item was not used. The staff noted that in LRA Section 2.3.1.4, the applicant stated its Unit 1 uses Westinghouse Model F recirculating SGs and Unit 2 uses AREVA 61/19T recirculating SGs. The staff reviewed UFSAR Figures 5.1-3 and 5.1-3A for Units 2 and 1, respectively, and confirmed that the SGs do not have lattice bars and, therefore, finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-79 addresses nickel-alloy SG tubes exposed to secondary feedwater/steam subject to denting due to corrosion of the steel tube support plate. The applicant stated that this line item is not applicable because its SGs do not contain steel tube support plates, so the applicable GALL Report line item was not used. The staff reviewed the applicant's UFSAR and confirmed that the SGs for Units 1 and 2 do not use steel tube support plates and, therefore, finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-82 addresses the stainless steel SG primary-side divider plate exposed to reactor coolant subject to cracking due to SCC for this component group. The applicant stated that this line item is not applicable because its SG primary-side divider plates are made of nickel alloy, so the applicable GALL Report line item was not used. The staff reviewed UFSAR Section 5.5.2.2.1 and confirmed that the divider plate for the SG is fabricated of nickel alloy. The staff noted that in LRA Table 3.1.1, item 3.1.1-81, nickel-alloy primary head divider plates are managed for cracking due to SCC. Based on its review as described above, the staff finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-84 addresses nickel-alloy SG components such as secondary-side nozzles - vent, drain, and instrumentation exposed to secondary feedwater and/or steam subject to cracking due to SCC for this component group. The applicant stated that this line item is not applicable because this component, material, environment, and aging effect/mechanism combination does not apply since its plant does not have nickel-alloy SG secondary-side nozzles exposed to secondary feedwater and/or steam.

The staff noted that the applicant's description of its SGs design in LRA Sections 2.3.1.4 and B.2.1.10, as well as in UFSAR Revision 24, did not provide sufficient information associated with the materials of the SG secondary-side nozzles to determine whether the aging effect of SCC is applicable for those components. Moreover, the staff noted that in LRA Table 3.1.2-4, the applicant included nickel-alloy spray nozzles exposed to treated water, but did not address the aging effect of SCC.

By letter dated July 30, 2010, the staff issued RAI 3.1.1.84-01 requesting that the applicant clarify whether its SGs contain any nickel-alloy SG components exposed to secondary water and/or steam or revise accordingly its proposed LRA Table 3.1.1, item 3.1.1-84. The staff further requested that the applicant justify why cracking due to SCC is an aging effect that does not need to be addressed for the nickel-alloy SG spray nozzles exposed to treated water.

In its response dated August 26, 2010, the applicant stated that it inadvertently omitted the aging effect and mechanism of cracking due to SCC for the nickel-alloy spray nozzles, which are installed in Unit 1 SGs. The applicant stated in LRA Table 3.1.2-4, the spray nozzles are the J-nozzles constructed of nickel alloy and are connected to each of the Unit 1 carbon steel SG feedwater rings. The applicant also explained that Unit 2 J-nozzles are constructed of stainless steel and are connected to each of the Unit 2 stainless steel feedwater rings which were added to LRA Table 3.1.2-4 as stated in response to RAI 3.1.2.2.14-01, dated July 28, 2010. The applicant revised LRA Table 3.1.1, item 3.1.1-84 and LRA Table 3.1.2-4 by identifying this item as consistent with the GALL Report and stated the Water Chemistry Program and the One-Time Inspection Program will be used to manage cracking due to SCC for the Unit 1 nickel-alloy SG spray nozzles exposed to secondary feedwater and/or steam, consistent with GALL AMR item IV.D2-9. The applicant also revised LRA Table 3.1.2-4 to include the aging effects of cracking due to SCC and loss of material due to pitting and crevice corrosion for the added Unit 2 stainless steel spray nozzles. In the revised LRA Table 3.1.2-4, the applicant stated that these aging effects are managed with the Water Chemistry Program and the One-Time Inspection Program by selecting GALL Report items VIII.F-23 and VIII.F-24. The applicant also indicated that LRA Table 3.1.1, item 3.1.1-84 pertains to the OTSGs, whereas its SGs are recirculating SGs. The staff noted that this item appears only in the GALL Report, Revision 1, Volume 2, Table IV.D2 for OTSGs; however, the staff noted that it does not preclude the associated aging effect from being applicable to a component with a similar material/environment/aging effect and mechanism combination in recirculating SGs.

The staff reviewed the applicant’s response to RAI 3.1.1.84-01 and finds it not acceptable because it was not clear to the staff whether the applicant considered the SG spray nozzles as piping nozzles that are addressed by the GALL Report AMR items for piping elements, or as J-nozzles that should be considered as SG secondary internals and, therefore, are managed by the Steam Generator Tube Integrity Program. The staff was also not clear whether generic note A was appropriate, since the applicant selected AMPs not directly applicable to these components.

In a conference call on September 9, 2010, to discuss and clarify the applicant’s response, the applicant agreed to revise LRA Table 3.1.2-4 according to the staff’s concerns.

In a letter dated October 8, 2010, the applicant revised LRA Table 3.1.2-4 to replace the One-Time Inspection Program with the Steam Generator Tube Integrity Program to manage loss of material due to pitting and crevice corrosion and cracking due to SCC for the Unit 1 SG spray nozzles, the Unit 2 SG spray nozzles, and SG feedwater ring. The applicant also revised the GALL Report item from IV.D2-9 to IV.D1-14 in LRA Table 3.1.2-4 and the associated Table 3.1.1 item from 3.1.1-84 to 3.1.1-74, since the Unit 1 nickel-alloy SG spray nozzles are considered an internal nozzle. In addition, the applicant provided additional line items to LRA Table 3.1.2-4 for the following component types: Unit 1 nickel-alloy SG spray nozzles, Unit 2 stainless steel SG spray nozzles, Unit 1 carbon steel SG feedwater ring, and Unit 2 SG stainless steel feedwater ring exposed to treated water and treated water greater than 60 °C (140 °F), since these environments affected both the internal and external surfaces of these components. The applicant stated that the Steam Generator Tube Integrity Program will be used to manage the applicable aging effects for the internal and external surfaces of these components, in complement with the Water Chemistry Program, and revised plant-specific note 2 accordingly. The applicant also revised LRA Table 2.3.1-4 to reflect the separation between SG feedwater rings and supports, Unit 1 and Unit 2 SG spray nozzles, and Unit 1 and Unit 2 SG feedwater rings. The applicant updated LRA Table 3.1.1, item 3.1.1-74 to include the Unit 1 nickel-alloy SG spray nozzles in the list of components managed with this item for cracking due to SCC and loss of material due to crevice corrosion and fretting. The applicant revised LRA Table 3.1.1, item 3.1.1-84 to state that this item is not applicable because the installed SGs do not have attached nozzles constructed of nickel alloy exposed to secondary feedwater/steam, and the Unit 1 nickel-alloy SG spray nozzles are considered SG internal components and are evaluated under item 3.1.1-74. The applicant revised LRA Table 3.4.1, item 3.4.1-14 and LRA Section 3.4.2.2.6 to include the Unit 2 stainless steel SG feedwater ring and spray nozzles exposed to treated water greater than 60 °C (140 °F) to be managed for cracking due to SCC. The applicant also revised LRA Table 3.4.1, item 3.4.1-16 and LRA Section 3.4.2.2.7.1 to include Unit 2 stainless steel SG feedwater ring and supports and spray nozzles exposed to treated water to be managed for loss of material due to pitting and crevice corrosion. In LRA Table 3.4.1, items 3.4.1-14 and 3.4.1-16, the applicant stated that components in the SG system have been aligned to these item numbers based on material, environment, and aging effect and that the Steam Generator Tube Integrity Program will be substituted to verify the effectiveness of the Water Chemistry Program, to manage cracking due to SCC and the loss of material due to pitting and crevice corrosion, respectively, in the Unit 2 stainless steel SG feedwater ring and spray nozzles exposed to treated water or treated water greater than 60 °C (140 °F) for this system.

Based on its review, the staff finds the applicant's response to RAI 3.1.1.84-01 acceptable because the applicant has revised LRA sections related to its SGs in order to include the appropriate components for which it identified the adequate aging effects and AMPs and revised the plant-specific notes. The staff's evaluations of the applicant's revisions to LRA Table 3.1.2-4; LRA Sections 3.1.2.2.2.2, 3.4.2.2.6, and 3.4.2.2.7.1; LRA Table 3.1.1, item 3.1.1-16; and LRA Table 3.4.1, items 3.4.1-14 and 3.4.1-16 are documented in SER Sections 3.1.2.3.4, 3.1.2.2.2.2, 3.4.2.2.6, and 3.4.2.2.7.1, respectively. The staff's concern described in RAI 3.1.1.84-01 is resolved.

During the August 2010 NRC Region I license renewal inspection, a discrepancy between LRA Table 3.1.2-4 and the Steam Generator Tube Integrity Program basis document was noted. The staff noted that SG moisture separators – vanes and dryers and the Unit 1 SG secondary flow distribution baffle were contained in the program basis document, but did not appear in the LRA. The staff also noted that the SG loose part monitoring (i.e., trapping) system of the Unit 2 SGs only was not included in the LRA for aging management. The staff noted that a degradation of these SG secondary-side internals could affect the integrity of SG tubes and questioned the applicant about these discrepancies and whether it needed to manage the aging effects for those components.

In its response dated August 26, 2010, the applicant explained that it removed SG moisture separators – vanes and dryers and the Unit 1 SG secondary flow distribution baffle from the LRA since they were determined to not have an intended function. The applicant stated that upon further review, it has been concluded that the intended function of structural support will be applied to these SG secondary internal components. The applicant further stated that the vanes and dryers are constructed of carbon steel for both units and that the Unit 1 SGs contain the secondary flow distribution baffle, which is constructed of stainless steel. The applicant further stated that the SG loose part monitoring system on Unit 2 only is constructed of stainless steel, is considered a secondary internal component, and has the intended function of structural support. The applicant revised LRA Table 2.3.1-4 to add a new component, SG secondary internals, and its intended function of structural support. The applicant revised LRA Table 3.1.2-4 to provide AMR line items for this added component of SG secondary internals fabricated from carbon steel or stainless steel and exposed to treated water (external) and treated water greater than 60 °C (140 °F) with the following aging effects: loss of material due to general, pitting, and crevice corrosion; wall thinning due to flow-accelerated corrosion; loss of material due to pitting and crevice corrosion; and cracking due to SCC. The applicant revised LRA Table 3.1.1, item 3.1.1-16 and LRA Section 3.1.2.2.2.2 to include the steel SG secondary internals exposed to secondary feedwater and steam to be managed for loss of material due to general, pitting, and crevice corrosion.

The staff reviewed the applicant's response and finds it not acceptable because the staff was not clear whether a separate intended function of direct flow would be appropriate for some SG secondary internals, such as the flow distribution baffle, and whether generic note A was appropriate. The staff also noted that the applicant selected the One-Time Inspection Program to manage the aging effect of loss of material due to pitting and crevice corrosion, in complement with the Water Chemistry Program. However, the staff noted that this aging effect for the SG secondary internals should be managed with the Steam Generator Tube Integrity Program in order to assess any degradation of the secondary side SG components that could affect the integrity of the SG tube bundles.

In a conference call on September 9, 2010, to discuss and clarify the applicant's response, the applicant did not agree with the need to include a new intended function and agreed to revise LRA Table 3.1.2-4 according to the staff's other concerns.

In a letter dated October 8, 2010, the applicant stated that it replaced the One-Time Inspection Program with the Steam Generator Tube Integrity Program to manage the aging effect of loss of material due to pitting and crevice corrosion for the stainless steel SG secondary internals exposed to treated water and revised the plant-specific note from "C" to "E, 3" associated with the Steam Generator Tube Integrity Program and from "A" to "C" associated with the Water Chemistry Program for these components. The applicant revised LRA Table 3.4.1, item 3.4.1-16 and LRA Section 3.4.2.2.7.1 to include these components to be managed for loss of material due to pitting and crevice corrosion. In addition, for the SG tubesheets, the applicant revised LRA Table 3.1.1, item 3.1.1-16 by substituting the Steam Generator Tube Integrity Program to verify the effectiveness of the Water Chemistry Program, instead of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, to manage the loss of material due to general, pitting, and crevice corrosion in the steel tubesheets and updated LRA Section 3.1.2.2.2.2 accordingly. The applicant also corrected the plant-specific note "E, 4" to "E, 3" when the Steam Generator Tube Integrity Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Based on its review, the staff finds the applicant's response to the demand of clarification acceptable because the applicant has revised LRA sections related to its SGs in order to include the appropriate components for which it identified the adequate aging effects and AMPs and revised the plant-specific notes. The staff's evaluations of the applicant's revisions to LRA Table 3.1.2-4 and LRA Sections 3.1.2.2.2.2 and 3.4.2.2.7.1; LRA Table 3.1.1, item 3.1.1-16; and LRA Table 3.4.1, item 3.4.1-16 are documented in SER Sections 3.1.2.2.2.2 and 3.4.2.2.7.1, respectively. The staff's concern described in its demand of clarification is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.1.1, item 3.1.1-87 addresses steel piping, piping components, and piping elements in concrete. The GALL Report states that there is not an AERM. The applicant stated that this line item is not applicable because its reactor vessel, internals, and RCS have no in-scope steel piping, piping components, or piping elements embedded in concrete, so the applicable GALL Report line item was not used. The staff reviewed the applicant's UFSAR and confirmed that no in-scope steel piping, piping components, and piping elements in concrete are present in these systems and, therefore, finds the applicant's determination acceptable.

3.1.2.1.2 Loss of Preload Due to Self-Loosening

LRA Table 3.1.1, item 3.1.1-52 addresses stainless, carbon, and low-alloy steel closure bolting exposed externally to indoor uncontrolled air or outdoor air, which are being managed for loss of preload due to self-loosening. The LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that these aging effects are adequately managed. The associated AMR line items cite generic note E.

For those line items associated with generic note E, GALL AMP XI.M18 recommends using visual inspections and industry guidance on proper selection of bolting materials, lubricants, and torque to manage the aging of these line items. In its review of components associated with item 3.1.1-52 for which the applicant cited generic note E, the staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of stainless steel, carbon, and low-alloy steel bolting through the use of visual inspections and industry guidance on bolting materials, lubricants, and torque.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.4. In its review of components associated with item 3.1.1-52, the staff finds the applicant's proposal to manage aging using the Inspection of the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because: (1) its visual inspections are effective methods for detecting the applicable aging effects; (2) incorporation of industry guidance on proper selection of bolting materials, lubricants, and torque are effective methods for preventing loss of preload; (3) the frequency of monitoring is adequate to prevent significant degradation; and (4) the inspection methods are consistent with the GALL Report recommended AMP.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.3 Loss of Fracture Toughness Due to Thermal Aging Embrittlement

LRA Table 3.1.1, item 3.1.1-55 addresses loss of fracture toughness due to thermal aging embrittlement of CASS Class 1 pump casings and valve bodies and bonnets exposed to reactor coolant greater than 250 °C (482 °F). LRA item 3.1.1-55 also indicates that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is credited to manage the aging effect and ASME Code Case N-481 provides an alternative for the aging management. LRA Table 3.1.2-1 indicates that the component under LRA item 3.1.1-55 is the casings of the RCPs and the aging effect is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and TLAA (LRA Section 4.4.4).

LRA Table 3.1.2-1 further addresses two AMR line items to manage the loss of fracture toughness of the CASS Class 1 pump casings. In the LRA table, note A is claimed for the line item that credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The LRA indicates that note A means that the item is consistent with the GALL Report item for component, material, environment, aging effect, and AMP. In addition, LRA Table 3.1.2-1 claims note E for the CASS Class 1 pump casing line item that credits a TLAA. The LRA indicates that note E means that the item is consistent with the GALL Report item for component, material, environment, and aging effect, but a different AMP is credited or the GALL Report identified a plant-specific AMP. The applicant further stated, using note 4, that ASME Code Case N-481 is applicable to Salem, therefore, its aging management will be evaluated as a TLAA. LRA Section 4.4.4 also indicates that the code case allows the replacement of ASME Code Section XI volumetric examinations of primary loop pump casings with fracture-mechanics-based integrity evaluations (Item (d) of the code case) supplemented by specific visual examinations (Items (a), (b), and (c) of the code case). In LRA Section 4.4.4, the applicant indicated that the applicant's TLAA is associated with Item (d) of the code case.

The staff reviewed the AMR line items against GALL Report, Volume 1, Table 1, ID 55 and Volume 2, item IV.C2-6. The staff noted that the GALL Report, Volume 2, under item IV.C2-6, recommends GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," to manage the aging effect. The GALL Report further indicates that for pump casings and valve bodies, screening for susceptibility to thermal aging is not necessary. The staff also noted that the GALL Report indicates that the ASME Code Section XI inspection requirements are sufficient for managing the aging effect and, alternatively, the requirements of ASME Code Case N-481 for pump casings are sufficient for managing the aging effect. Therefore, the staff finds that the applicant's aging management method, which uses the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program with the alternative requirements of ASME Code Case N-481, is consistent with the GALL Report.

The staff's evaluations of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the applicability of ASME Code Case N-481, including the TLAA, are documented in SER Sections 3.0.3.1.1 and 4.4.4.2, respectively. In its review, the staff finds that the use of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and ASME Code Case N-481, including the TLAA, is acceptable to manage the loss of fracture toughness of the CASS Class 1 pump casings because: (1) the applicant's proposed aging management method and programs are consistent with the GALL Report; and (2) as required by ASME Code Case N-481, the applicant's plant-specific analysis demonstrates the safety and serviceability of the pump casings and the applicant's TLAA results demonstrate that the stability of the postulated flaws remains valid during the period of the extended operation.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.4 Loss of Fracture Toughness Due to Thermal Aging and Neutron Irradiation Embrittlement

LRA Table 3.1.1, item 3.1.1-80 addresses loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS reactor vessel internals exposed to reactor coolant and neutron flux. LRA item 3.1.1-80 also indicates that the PWR Vessel Internals Program will be substituted to manage the aging effect in CASS reactor vessel internal components exposed to reactor coolant and neutron flux. In addition, LRA Section B.2.0 indicates that GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," is not used for the applicant's aging management.

LRA Table 3.1.2-3 further addresses one AMR line item to manage the loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of the CASS incore guide cruciforms exposed to reactor coolant and neutron flux. The applicant claimed note E for the

LRA line item and the LRA indicates that note E means that the item is consistent with the GALL Report item for component, material, environment, and aging effect, but a different AMP is credited or the GALL Report identified a plant-specific AMP. The staff noted that note E is claimed because the applicant credited the PWR Vessel Internals Program in conjunction with the UFSAR supplement commitment (LRA Section A.2.1.7) rather than GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," that is recommended by the GALL Report.

The staff reviewed the AMR line item in comparison with GALL Report, Volume 1, Table 1, ID 80 and Volume 2, items IV.B2-21 and IV.B2-37. The staff noted that the GALL Report, under items IV.B2 21 and IV.B2-37, recommends GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," to manage the loss of fracture toughness due to thermal aging and neutron irradiation for the lower internals and upper internals of the Westinghouse PWR vessels, respectively.

In its review, the staff noted that LRA Table 3.1.2-3 does not address loss of fracture toughness due to thermal aging and neutron irradiation embrittlement for RCCA guide tube assemblies (lower flanges), upper internals assembly (upper support column bases), and upper internals assembly (static flow mixers) although the LRA indicates that the material of the components is CASS and the PWR Vessel Internals Program is credited to manage the changes in dimensions due to void swelling and cracking due to SCC and IASCC. The staff also noted that the aging effects addressed in the LRA table indicate that neutron irradiation is applicable to the components because the void swelling and IASCC require the exposure of the components to neutron irradiation. In addition, the staff noted that the omission of the components in managing loss of fracture toughness for the CASS reactor vessel internals is not consistent with GALL Report, Volume 1, Table 1, ID 80 that addresses loss of fracture toughness due to thermal aging and neutron irradiation embrittlement for CASS reactor vessel internals including upper internals assembly, lower internal assemblies, and control rod guide tube assembly.

By letter dated June 11, 2010, the staff issued RAI 3.1.2.1-01 requesting that the applicant describe what program is used to manage loss of fracture toughness due to thermal aging and neutron irradiation embrittlement for RCCA guide tube assemblies (lower flanges), upper internals assembly (upper support column bases), and upper internals assembly (static flow mixers) that are described in LRA Table 3.1.2-3. The staff also requested that, if the applicant does not manage loss of fracture toughness for the CASS components, the applicant justify why it is not required to manage loss of fracture toughness for the components.

In its response to the RAI, dated July 8, 2010, the applicant indicated that the RCCA guide tube assemblies (lower flanges), the upper internals assembly (static flow mixers), and the upper internals assembly (upper support column bases) components were inadvertently omitted from the AMR to manage loss of fracture toughness. The applicant also indicated that these components are within the reactor vessel internals and are exposed to reactor coolant and neutron flux and have an aging effect of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement. The applicant further indicated that the applicant credits the PWR Vessel Internals Program to manage the aging effect for the components and that LRA Table 3.1.2-3 is revised to add these component types for adequate aging management of loss of fracture toughness.

Based on its review, the staff finds the applicant's response to RAI 3.1.2.1-01 acceptable because the addition of the aforementioned AMR line items is consistent with the GALL Report and the applicant clarified that the PWR Vessel Internals Program is credited to manage loss of fracture toughness for the components. The staff's concern described in RAI 3.1.2.1-01 is resolved.

The staff's evaluation of the PWR Vessel Internals Program is documented in SER Section 3.0.3.3.1. In its review, the staff finds the proposed PWR Vessel Internals Program acceptable to manage the loss of fracture toughness for the CASS reactor vessel internals because: (1) the applicant's commitment to participate in the industry programs for investigating and managing aging effects on reactor internals ensures that adequate inspections and/or preventive measures are identified to manage the loss of fracture toughness for the CASS reactor vessel internal components, (2) the applicant's commitment to evaluate and implement the results of the industry programs as applicable to the reactor vessel internals can ensure that the aging management lessons and recommendations identified from the industry experience and programs are adequately implemented to the applicant's AMP, and (3) the applicant's commitment to submit an inspection plan for reactor internals to the NRC for review, upon completion of these programs, but not less than 24 months before the entering the period of the extended operation, can ensure the timely identification and adequate management of the effects of aging.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.5 Cracking Due to Primary Water Stress-Corrosion Cracking

LRA Table 3.1-1, item 3.1.1-81 addresses cracking due to PWSCC for the nickel alloy or nickel-alloy clad SG divider plate exposed to reactor coolant. The applicant credited its Water Chemistry Program to manage cracking due to PWSCC in the nickel-alloy SG primary channel head divider plate exposed to reactor coolant in the SGs

SRP-LR Section 3.1.2.2.13 identifies that cracking due to PWSCC could occur in PWR components made of nickel alloy and steel with nickel-alloy cladding, including RCPB components and penetrations inside the RCS such as pressurizer heater sheaths and sleeves, nozzles, and other internal components. GALL AMR item IV.D1-06 recommends GALL AMP XI.M2, "Water Chemistry," for PWR primary water for managing the aging effect of cracking in the nickel-alloy SG divider plate exposed to reactor coolant.

UFSAR Section 5.5.2.2.1 states that the divider plate is fabricated with Inconel 690 for the Unit 2 replacement SGs. The staff noted that the use of this Alloy 690 should prevent the aging effect of PWSCC. However, the applicant did not provide information related to the material of construction for the divider plate in the Unit 1 SGs.

The staff noted that, from foreign operating experience in SGs with a similar design to that of the applicant, extensive cracking due to PWSCC has been identified in SG divider plates made with Alloy 600, even with proper primary water chemistry. The staff noted that specifically, cracks have been detected in the stub runner, very close to the tubesheet/stub runner weld and with depths of almost a fourth of the divider plate thickness. Therefore, the staff noted that the applicant's Water Chemistry Program alone may not be effective in managing the aging effect of cracking due to PWSCC in the SG divider plate.

The staff noted that although these SG divider plate cracks may not have a significant safety impact in themselves, these cracks could impact adjacent items, such as the tubesheet and the channel head, if they propagate to the boundary with these components. The staff further noted that for the tubesheet, PWSCC cracks in the divider plate could propagate to the tubesheet cladding with possible consequences to the integrity of the tube-to-tubesheet welds. Furthermore, the staff noted for the channel head, the PWSCC cracks in the divider plate could propagate to the SG triple point and potentially affect the pressure boundary of the SG channel head.

By letter dated June 10, 2010, the staff issued RAI 3.1.1-01 requesting that the applicant discuss the materials of construction of the applicant's Unit 1 SG divider plate assembly; furthermore, if these materials are susceptible to cracking (e.g., Alloy 600 or the associated Alloy 600 weld materials), the staff requested the applicant to discuss the potential that cracking in the divider plate might propagate into other components (e.g., tubesheet cladding). The staff further requested that if propagation into these other components cannot be ruled out, the applicant should describe an inspection program (examination technique and frequency) for ensuring that there are no cracks propagating into other components (e.g., tubesheet and/or channel head) that could challenge the integrity of other adjacent components.

In its response dated July 8, 2010, the applicant described the materials of its SG divider plate assemblies, which are nickel Alloy 600 for the stub runner and the divider plate components and Alloy 82/182 for the welds that attach the divider plate and stub runner to each other and to the channel head and to the tubesheet. The applicant also provided additional elements in order to justify why the potential for cracking of Unit 1 Model F SG divider plate propagating into adjoining components and resulting in loss of the integrity of the RCPB would not be expected to occur and, therefore, why the SG divider plate assemblies do not require an AMP consisting of inspections for crack propagation.

Based on its review of the applicant's response, the staff noted that the applicant provided only qualitative arguments for concluding that divider plate crack growth is not a concern. The staff considered that this response did not provide a reasonable and sufficient basis for justifying the applicant's conclusions. Further, the staff noted that the use of analytical tools to predict the behavior of service-induced cracking (in other components) has not always bounded actual service performance of these cracks. In addition, the staff noted that the likely presence of cracks in Alloy 600 SG divider plate assemblies may result in a condition where these cracks could propagate into surrounding pressure boundary areas, such as the tube-to-tubesheet welds and the channel head.

Therefore, by letter dated September 29, 2010, the staff issued follow-up RAI 3.1.1-02 requesting that the applicant provide an AMP, changes to an existing AMP, or a commitment to inspection(s) that would demonstrate the condition of the SG divider plate assemblies to support a conclusion that there will be no adverse consequences of divider plate assembly degradation during the period of extended operation.

In its response to the RAI dated October 7, 2010, the applicant described industry plans to study the potential for divider plate crack growth and develop an industry-applied resolution to the concern through the EPRI Steam Generator Management Program (SGMP) Engineering and Regulatory Technical Advisory Group, which is expected to be completed by 2013. The applicant also described VT-3 inspection performed on each of the four Unit 1 SG divider plates during a 2004 outage, and visual examination performed in the spring outage of 2010 on the Alloy 600 bottom bowl drain. The applicant stated that these examinations identified no indications of degradation, although the staff concludes that these examinations would not be capable of detecting PWSCC cracking in these components. The applicant committed to perform an inspection of each of the four Unit 1 SGs to assess the condition of the divider plate assembly. The applicant also stated that the examination technique(s) used will be capable of detecting PWSCC in the SG divider plate assemblies and the associated welds. Moreover, the applicant stated that SG divider plate inspections will be completed within the first 10 years of the period of extended operation (i.e., prior to August 2026). In addition, the applicant stated that it also plans to remain involved with the ongoing industry studies related to divider plate cracking to ensure that any inspection requirements or other resolution actions promulgated to the industry are evaluated and implemented, as appropriate. Finally, the applicant stated that Commitment No. 50, covering the above inspection of each of the Unit 1 SGs to assess the condition of the divider plate assembly, will be added to the Table A.5 license renewal commitment list.

Based on its review, the staff finds the applicant's response to RAI 3.1.1-02 and associated Commitment No. 50 acceptable because the applicant will assess the condition of the divider plate assembly in each of the Unit 1 SGs by inspection during the period of extended operation, in a time period consistent with the detection of potential PWSCC cracks, and with appropriate examination techniques. The staff also notes that the applicant will remain involved with ongoing industry efforts related to the divider plate cracking issue. The staff's concerns described in RAIs 3.1.1-01 and 3.1.1-02 are resolved.

In a conference call on September 16, 2010, the applicant confirmed that all the materials constituting the divider plate assemblies for Unit 2 SGs are Alloy 690 and/or Alloy 52/152. As mentioned above, the staff considered that the use of these alloys should prevent the aging effect of PWSCC for the SG divider plate assemblies.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.6 Conclusion for AMRs Consistent with the GALL Report

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated 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 with the GALL Report AMRs. Therefore, the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.1.2.2 provides further evaluation of aging management as recommended by the GALL Report for the RCS components. The applicant provided 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 SCC and IGSCC
- crack growth due to cyclic loading
- loss of fracture toughness due to neutron irradiation embrittlement and void swelling
- cracking due to SCC
- cracking due to cyclic loading
- loss of preload due to stress relaxation
- loss of material due to erosion
- cracking due to flow-induced vibration
- cracking due to SCC and IASCC
- cracking due to PWSCC
- wall thinning due to flow-accelerated corrosion
- changes in dimensions due to void swelling
- cracking due to SCC and PWSCC
- cracking due to SCC, PWSCC, and IASCC
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation. The staff determined whether the applicant adequately addressed the issues for which further evaluation is recommended. 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 states fatigue is a TLAA as defined in 10 CFR 54.3. Furthermore, TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The applicant stated the evaluation of metal fatigue as a TLAA for the RCS, reactor vessel, reactor vessel internals, and SGs are discussed in LRA Section 4.3.

The applicant identified that the following AMRs in LRA Table 3.1.1 are applicable to this further evaluation item and that the analysis of metal fatigue for component addressed in these AMRs is a TLAA:

- Item 3.1.1-5 – The applicant stated that some of the Salem reactor vessel internal components designed to ASME Code Section III, Subsection NG requirements were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-3, the applicant identified that the reactor vessel internal lower internal assembly components were required to be analyzed in accordance with an applicable CUF analysis. The applicant stated that LRA Section 4.3 describes the evaluation of these TLAAs.

- Item 3.1.1-6 – The applicant stated that the Salem nickel-alloy tubes and sleeves in a reactor coolant and secondary feedwater or steam environment were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-4, the applicant identified SG tube plugs and tubes required to be analyzed for CUF analyses and that these TLAAs are discussed and evaluated in LRA Section 4.3.

- Item 3.1.1-7 – The applicant stated that the Salem steel and stainless steel RCPB closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, SG components, piping and components, external surfaces, and bolting were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Tables 3.1.2-1, 3.1.2-2, 3.1.2-4, 3.2.2-3, 3.3.2-2, 3.3.2-22, and 3.4.2-2, the applicant identified bolting, piping, fittings, branch connections, valves, nozzles, and SG components that are required to be analyzed for CUF analyses and that these TLAAs are discussed and evaluated in LRA Section 4.3.

- Item 3.1.1-8 – The applicant stated that the Salem steel, stainless steel, and nickel-alloy RCPB piping, piping components, piping elements, flanges, nozzles, safe ends, pressurizer vessel shell heads and welds, heater sheaths and sleeves, penetrations, and thermal sleeves were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Tables 3.1.2-1, 3.1.2-2, 3.2.2-3, and 3.3.2-2, the applicant identified pressurizer components, pump casings, piping, thermowells, valve bodies, restricting orifices, fittings, and branch connections that are required to be analyzed for CUF analyses and that these TLAAs are discussed and evaluated in LRA Section 4.3.

- Item 3.1.1-9 – The applicant stated that the Salem steel, stainless steel, nickel-alloy, and nickel-alloy or stainless steel cladding reactor vessel components, flanges, nozzles, penetrations, pressure housings, safe ends, thermal sleeves, vessel shells, heads, and welds were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-2, the applicant identified control rod assemblies, nozzles, and reactor vessel components that are required to be analyzed for CUF analyses and that these TLAAs are discussed and evaluated in LRA Section 4.3.

- Item 3.1.1-10 – The applicant stated that the Salem steel, stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding SG components were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-4, the applicant identified SG components that are required to be analyzed for CUF analyses and that these TLAAs are discussed and evaluated in LRA Section 4.3.

The staff reviewed LRA Section 3.1.2.2.1 against the general criteria in SRP-LR Section 3.1.2.1 for performing AMR reviews, as subject to the additional further evaluation criteria in SRP-LR Section 3.1.2.2.1, which state that fatigue is a TLAA as defined in 10 CFR 54.3 and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these type of TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff also reviewed LRA Section 3.1.2.2.1 and the AMRs discussed in this Section against the AMR items for evaluating PWR design cumulative fatigue damage, as given in AMR items 5–10 of Table 1 of the GALL Report, Volume 1, Revision 1, and the AMR items derived from these GALL Report, Volume 1 AMR items. With regard to LRA Table 3.1.1, items 3.1.1-1 through 3.1.1-4, the staff noted that these items are associated with BWR design plants and, therefore, not applicable to the applicant.

With regard to LRA Table 3.1.1, item 3.1.1-5, the staff noted that GALL AMR item IV.B2-31 identifies cumulative fatigue damage as an applicable aging effect for reactor vessel internal components and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included applicable line items in LRA Table 3.1.2-3 for reactor vessel internal components that received ASME Code Section III CUF analysis calculations consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of reactor vessel internals acceptable because it is consistent with the recommendations in SRP-LR Section 3.1.2.2.1. The staff evaluates the TLAA analysis for the reactor vessel internals components in SER Section 4.3.5.

With regard to LRA Table 3.1.1, item 3.1.1-6, the staff noted that GALL AMR item IV.D1-21 identifies cumulative fatigue damage as an applicable aging effect for SG tubes and sleeves and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included applicable line items in LRA Table 3.1.2-4 for SG tubes and sleeves that received ASME Code Section III CUF analysis calculations consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of SG tubes and sleeves acceptable because it is consistent with the recommendations in SRP-LR Section 3.1.2.2.1. The staff evaluates the TLAA analysis for the SG tubes and sleeves components in SER Section 4.3.1.

With regard to LRA Table 3.1.1, item 3.1.1-7, the staff noted that GALL AMR items IV.A2-4, IV.C2-10, IV.C2-23, and IV.D1-11 identify that cumulative fatigue damage is an applicable aging effect for steel and stainless steel RCPB closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, SG components, piping and components, external surfaces, and bolting and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included applicable line items in LRA Tables 3.1.2-1, 3.1.2-2, 3.1.2-4, 3.2.2-3, 3.3.2-2, 3.3.2-22, and 3.4.2-2 for bolting, piping, fittings, branch connections, valves, nozzles, and SG components that received ASME Code Section III CUF analysis calculations consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of bolting, piping, fittings, branch connections, valves, nozzles, and SG components acceptable because it is consistent with the recommendations in SRP-LR Section 3.1.2.2.1. The staff evaluates the TLAA analysis for the bolting, piping, fittings, branch connections, valves, nozzles, and SG components in SER Sections 4.3.1 and 4.3.3.

With regard to LRA Table 3.1.1, item 3.1.1-8, the staff noted that GALL AMR item IV.C2-25 identifies cumulative fatigue damage as an applicable aging effect for steel, stainless steel, and nickel-alloy RCPB piping, piping components, piping elements, flanges, nozzles and safe ends, pressurizer vessel shell heads and welds, heater sheaths and sleeves, penetrations, and thermal sleeves and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included applicable line items in LRA Tables 3.1.2-1, 3.1.2-2, 3.2.2-3, and 3.3.2-2 for pressurizer components, pump casings, piping, thermowells, valve bodies, restricting orifices, fittings, and branch connections that received ASME Code Section III CUF analysis calculations consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of pressurizer components, pump casings, piping, thermowells, valve bodies, restricting orifices, fittings, and branch connections acceptable because it is consistent with the recommendations in SRP-LR Section 3.1.2.2.1. The staff evaluates the TLAA analysis for the pressurizer components, pump casings, piping, thermowells, valve bodies, restricting orifices, fittings, and branch connections in SER Sections 4.3.1, 4.3.2, and 4.3.3.

With regard to LRA Table 3.1.1, item 3.1.1-9, the staff noted that GALL AMR item IV.A2-21 identifies cumulative fatigue damage as an applicable aging effect for steel, stainless steel, nickel-alloy, and nickel-alloy or stainless steel cladding reactor vessel components, flanges, nozzles, penetrations, pressure housings, safe ends, thermal sleeves, vessel shells, heads, and welds and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included applicable line items in LRA Table 3.1.2-2 for control rod assemblies, nozzles, and reactor vessel components that received ASME Code Section III CUF analysis calculations consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of control rod assemblies, nozzles, and reactor vessel components acceptable because it is consistent with the recommendations in SRP-LR Section 3.1.2.2.1. The staff evaluates the TLAA analysis for the control rod assemblies, nozzles, and reactor vessel components in SER Section 4.3.1.

With regard to LRA Table 3.1.1, item 3.1.1-10, the staff noted that GALL AMR item IV.D1-8 identifies cumulative fatigue damage as an applicable aging effect for steel, stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding SG components and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included applicable line items in LRA Table 3.1.2-4 for SG components that received ASME Code Section III CUF analysis calculations consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of SG components acceptable because it is consistent with the recommendations in SRP-LR Section 3.1.2.2.1. The staff evaluates the TLAA analysis for the SG components in SER Section 4.3.1.

Based on the programs identified, 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 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).

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

The staff reviewed LRA Section 3.1.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.

(1) LRA Section 3.1.2.2.2.1 refers to Table 3.1.1, item 3.1.1-12 and addresses steel SG tube bundle tie rod assemblies and anti-vibration bars exposed to treated water, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Water Chemistry Program and the Steam Generator Tube Integrity Program. In LRA Table 3.1.1, item 3.1.1-12, the applicant stated that the Steam Generator Tube Integrity Program will be used to verify the effectiveness of the Water Chemistry Program.

    The staff reviewed LRA Section 3.1.2.2.2.1 against the criteria in SRP-LR Section 3.1.2.2.2.1, which state that loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG shell assembly exposed to secondary feedwater and steam. The SRP-LR states that the existing program relies on control of reactor water chemistry to mitigate corrosion and that the effectiveness of the chemistry control program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the chemistry control program. The SRP-LR states that a one-time inspection program of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Water Chemistry and Steam Generator Tube Integrity programs and its evaluations are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with LRA item 3.1.1-12, the staff noted that the applicant had extended the application of SRP-LR Table 3.1.1, item 3.1.1-12, initially for the steel OTSG shell assemblies exposed to secondary feedwater and steam to secondary steel components, such as the tube bundle tie rod assembly and anti-vibration bars exposed to treated water, for its Unit 1 replacement recirculating SGs. The staff finds this substitution acceptable because the combination of material/environment/aging effect, as identified by the applicant, is consistent with the GALL Report recommendations. The staff also noted that the applicant had assigned generic note E to the AMR line item stating that the Steam Generator Tube Integrity Program would be used for aging management. Because the GALL Report credits use of the One-Time Inspection Program to verify the Water Chemistry Program's effectiveness, the staff finds the applicant's use of generic note E to be acceptable.

The staff noted that the Water Chemistry Program implements primary water and secondary water chemistry control consistent with the recommendations of the current EPRI guidelines for PWR primary water and secondary water chemistry control and that operating within these guidelines provides mitigation for the aging effect of loss of material due to general, pitting, and crevice corrosion for steel SG components. The staff further noted that the Steam Generator Tube Integrity Program includes periodic visual inspections that are capable of detecting loss of material for components within its scope. The staff finds the applicant's proposal to manage the aging effect of loss of material due to general, pitting, and crevice corrosion for the steel SG tube bundle tie rod assemblies and anti-vibration bars by using the Water Chemistry Program and the Steam Generator Tube Integrity Program acceptable because: (a) the Water Chemistry Program provides mitigation for this aging effect and its use is consistent with the recommendations of the GALL Report, and (b) the Steam Generator Tube Integrity Program provides periodic visual inspections that are capable of detecting loss of material due to corrosion and thereby verifying effectiveness of the Water Chemistry Program for these SG components.

(2) SRP-LR Section 3.1.2.2.2.2 refers to Table 3.1.1, item 3.1.1-13, which applies to BWR isolation condenser components and is not applicable to the Salem units, which are PWRs.

(3) SRP-LR Section 3.1.2.2.2.3 refers to Table 3.1.1, items 3.1.1-14 and 3.1.1-15, which apply to BWR reactor vessel and RCPB components and are not applicable to the Salem units, which are PWRs.

(4) LRA Section 3.1.2.2.2.2 refers to Table 3.1.1, item 3.1.1-16 and addresses: (a) steel SG components (secondary manways and covers, tubesheets, upper head, upper shell, conical shell, lower shell), piping components and connections, and main feedwater and main steam nozzles exposed to steam and treated water, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Water Chemistry and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs; and (b) steel feedwater inlet ring and supports exposed to treated water, which are being managed for loss of material due to general, pitting, and crevice

corrosion by the Water Chemistry and the Steam Generator Tube Integrity programs. In LRA Table 3.1.1, item 3.1.1-16, the applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to verify the effectiveness of the Water Chemistry Program in the steel SG components (secondary manways and covers, tubesheets, upper head, upper shell, conical shell, lower shell), piping components and connections, and main feedwater and main steam nozzles and that the Steam Generator Tube Integrity Program will be used to verify the effectiveness of the Water Chemistry Program in the steel SG feedwater inlet ring and supports.

The staff reviewed LRA Section 3.1.2.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.4, which state that loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone components exposed to secondary feedwater and steam and that the existing program relies on control of chemistry to mitigate corrosion and ISI to detect loss of material. The SRP-LR further states that according to NRC IN 90-04, the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist and that for Westinghouse Model 44 and 51 SGs, the GALL Report recommends an augmented inspection.

The staff noted in LRA Section 2.3.1.4 that the Unit 1 SGs are described as Westinghouse Model F recirculating SGs and the Unit 2 SGs are described as AREVA 61/19T SGs. The staff confirmed that these descriptions are consistent with the SG descriptions in the applicant's UFSAR Section 5.5.2.2. Because the applicant's SGs are not Westinghouse Model 44 or 51, the staff finds that the GALL Report's recommendations related to augmented inspections are not applicable for the applicant's SGs.

The staff noted that the applicant had extended the application of SRP-LR Table 3.1.1, item 3.1.1-16, initially for the steel SG upper and lower shell and transition cone exposed to secondary feedwater and steam, to other secondary steel SG components. The staff finds this addition acceptable because the combination of material/environment/aging effect, as identified by the applicant, is consistent with the GALL Report recommendations.

In a letter dated August 26, 2010, responding to RAIs 3.1.1.66-01 and 3.1.1.84-01, and in a subsequent letter dated October 8, 2010, documenting follow-up clarification, the applicant revised a number of AMR items in LRA Table 3.1.2-4 that refer to LRA Table 3.1.1, item 3.1.1-16. The staff reviewed all of the changes to the AMR items that refer to LRA Table 3.1.1, item 3.1.1-16. The staff noted that for steel SG components exposed to treated water, the applicant identified the aging effect of loss of material due to general, pitting, and crevice corrosion. The staff also noted that in all instances, the applicant proposed to manage the loss of material aging effect with a combination of the Water Chemistry Program and either the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program or the Steam Generator Tube Integrity Program.

The staff reviewed the applicant's Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs and its evaluations are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.1, respectively. In its review of components associated with LRA item 3.1.1-16, for which the applicant credits the Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs, the staff found the applicant's proposal to manage aging using these programs acceptable because: (a) the applicant's Water Chemistry Program follows current EPRI secondary water chemistry guidelines and provides mitigation for the aging effect loss of material due to corrosion, and (b) the inspections required by ASME Code Section XI are capable of detecting loss of material due to corrosion, if it should occur, and thereby are capable of verifying the effectiveness of the Water Chemistry Program.

The staff also reviewed the applicant's Steam Generator Tube Integrity Program and its evaluations are documented in SER Section 3.0.3.1.8. In its review of components associated with LRA item 3.1.1-16, the staff noted that the applicant had assigned generic note E to the AMR line items stating that the Steam Generator Tube Integrity Program would be used to verify the effectiveness of the Water Chemistry Program. Because the GALL Report credits use of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to verify the Water Chemistry Program's effectiveness, the staff finds the applicant's use of generic note E to be acceptable.

The staff noted that the SG components for which the applicant credits the Steam Generator Tube Integrity Program are the carbon steel Unit 1 feedwater rings, feedwater ring supports, and secondary internals, and the low-alloy steel tubesheets. The staff also noted that surface inspection of these components is not required by ASME Code Section XI. In its review of the Steam Generator Tube Integrity Program, the staff found that the program includes periodic visual inspections that are capable of detecting loss of material for components within its scope and that the components listed are within the scope of the applicant's Steam Generator Tube Integrity Program. The staff finds the applicant's proposal to manage the aging effect of loss of material due to general, pitting, and crevice corrosion of the carbon steel SG feedwater ring and supports, and the secondary internals, and of the low-alloy steel SG tubesheets using the Water Chemistry Program and the Steam Generator Tube Integrity Program acceptable because: (a) the Water Chemistry Program provides mitigation for this aging effect and its use is consistent with the recommendations of the GALL Report, (b) the Steam Generator Tube Integrity Program provides periodic visual inspections that are capable of detecting loss of material due to corrosion and thereby verifying effectiveness of the Water Chemistry Program for these SG components, (c) the components are within the scope of the applicant's Steam Generator Tube Integrity Program, and (d) the Steam Generator Tube Integrity Program is not being used in lieu of inspections specified in ASME Code Section XI requirements.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2 criteria. For those line items that apply to LRA Section 3.1.2.2.2, 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).

3.1.2.2.3 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 3.1.2.2.3.1 addresses loss of fracture toughness due to certain aspects of neutron irradiation embrittlement as an aging effect that the applicant will manage through conducting TLAAs, consistent with the SRP-LR. The evaluation of these TLAAs is discussed in LRA Section 4.2.

SRP-LR Section 3.1.2.2.3.1 states that "certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2 of this SRP-LR."

As discussed in SER Section 4.2, loss of fracture toughness due to neutron irradiation embrittlement is limited to RPV beltline and extended beltline materials having a neutron fluence greater than 1×10^{17} n/cm^2 (E > 1.0 MeV) at the end of the period of extended operation. SER Section 4.2 accepted the applicant's evaluation of RPV neutron embrittlement in terms of upper-shelf energy (USE), PTS, and P-T limits, which represent a complete set of analytical means for predicting and managing loss of fracture toughness due to neutron irradiation embrittlement. Therefore, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.3.1 criteria. The staff also confirmed that LRA Table 3.1.2-2 correctly identifies the item under this aging effect (IV.A2-23 for RPV shell) in GALL Report Table IV.A2, "Reactor Vessel, Internals, and Reactor Coolant System/Reactor Vessel (PWR)." LRA Table 3.1.2-2 did not list GALL Report item IV.A2-16 for RPV nozzles under this aging effect. This is acceptable because the estimated neutron fluence at the end of the period of extended operation for Salem Units 1 and 2 RPV nozzles is less than 1×10^{17} n/cm^2 (E > 1.0 MeV).

(2) LRA Section 3.1.2.2.3.2 addresses loss of fracture toughness due to neutron irradiation embrittlement as an aging effect that the applicant will manage, consistent with the SRP-LR, by the Reactor Vessel Surveillance Program. This LRA Section states that the Reactor Vessel Surveillance Program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) determine the need for operating restrictions on the inlet temperature, neutron spectrum, and neutron flux.

SRP-LR Section 3.1.2.2.3.2 states that:

> Loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further staff evaluation is required for license renewal. Specific recommendations for an acceptable AMP are provided in Chapter XI, Section M31 of the GALL Report.

As indicated in SER Section 3.0.3.2.9, the staff accepted the applicant's Reactor Vessel Surveillance Program as capable of providing sufficient plant-specific material data and dosimetry to monitor the Salem RPVs' irradiation embrittlement at the end of the period of extended operation. Hence, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.3.2 criteria. The staff also confirmed that LRA Table 3.1.2-2 correctly identified the GALL Report Table IV.A2 item under this aging effect (IV.A2-24 for RPV shell). However, similar to SER Section 3.1.2.2.3.1, LRA Table 3.1.2-2 did not list GALL Report item IV.A2-17 for RPV nozzles under this aging effect. This is acceptable because the estimated neutron fluence at the end of the period of extended operation for Salem Units 1 and 2 RPV nozzles is less than 1×10^{17} n/cm^2 (E > 1.0 MeV).

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.3 criteria. For those line items that apply to LRA Section 3.1.2.2.3, 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).

3.1.2.2.4 Cracking Due to Stress-Corrosion Cracking and Intergranular Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

(1) LRA Section 3.1.2.2.4 addresses cracking due to SCC and IGSCC, stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.1.2.2.4 states that cracking due to SCC and IGSCC may occur in the stainless steel and nickel-alloy BWR top head enclosure vessel flange leak detection lines.

The staff finds that SRP-LR Section 3.1.2.2.4, item 1 is not applicable to the Salem units because they are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

(2) LRA Section 3.1.2.2.4 addresses cracking due to SCC and IGSCC, stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.1.2.2.4 states that cracking due to SCC and IGSCC may occur in stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff finds that SRP-LR Section 3.1.2.2.4, item 2 is not applicable to the Salem units because they are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.4, items 1 and 2 do not apply to Salem because the guidance is applicable only to BWR-designed reactors and Salem, a PWR, is not a BWR design.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

The staff reviewed LRA Section 3.1.2.2.5 against the criteria in SRP-LR Section 3.1.2.2.5.

LRA Section 3.1.2.2.5, associated with LRA Table 3.1.1, item 3.1.1-21, addresses cracking due to cyclic loading in reactor vessel shell forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant. The applicant stated that this item is not applicable because the reactor vessel shell is not fabricated of SA 508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process. The staff reviewed UFSAR Section 5 and noted that the reactor vessel shell is not fabricated of SA 508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process and, therefore, finds the applicant's claim acceptable.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

The staff reviewed LRA Section 3.1.2.2.6 against the criteria in SRP-LR Section 3.1.2.2.6. LRA Section 3.1.2.2.6 addresses loss of fracture toughness due to neutron irradiation embrittlement and void swelling as an aging effect that the applicant will manage, consistent with the SRP-LR, by the PWR Vessel Internals Program which is committed to: (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval. This commitment is also identified in UFSAR Section A.2.1.7, "PWR Vessel Internals."

SRP-LR Section 3.1.2.2.6 states that:

> Loss of fracture toughness due to neutron irradiation embrittlement and void swelling could occur in stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant and neutron flux. The GALL Report recommends no further aging management review if the applicant commits in the [U]FSAR Supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

As described in LRA Section 3.1.2.2.6, the applicant made a commitment to incorporate all three GALL Report requirements stated above to manage this aging effect. The PWR Vessel Internals Program contains this commitment (Commitment No. 7). Commitment No. 7 is also identified in the UFSAR Section A.2.1.7. Therefore, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.6 criteria for managing the aging effects due to neutron irradiation embrittlement and void swelling. The staff also examined LRA Table 3.1.2-3 to find out whether the RPV internals subjected to these aging effects are consistent with those listed in GALL Report Table IV.B2. The staff confirmed that LRA Table 3.1.2-3 identified all GALL Report Table IV.B2 items and the components under them for this aging effect (IV.B2-3, IV.B2-6, IV.B2-9, IV.B2-17, IV.B2-18, and IV.B2-22). For GALL Report item IV.B2-6, the applicant identified in LRA Table 3.1.2-3, two additional RPV internals components (the core support locking nut and the bolts and dowels of the thermal shield) as being different but consistent with this GALL Report item for material, environment, and aging effect. For four of the remaining five GALL Report Table IV.B2 items, LRA Table 3.1.2-3 provides a set of subcomponents to represent a single component in GALL Report Table IV.B2. The applicant's approach of including additional components under the required AMP for GALL Report item IV.B2-6 is acceptable.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.6 criteria. For those line items that apply to LRA Section 3.1.2.2.6, 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).

3.1.2.2.7 Cracking Due to Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.7 against the criteria in SRP-LR Section 3.1.2.2.7.

(1) LRA Section 3.1.2.2.7.1 addresses cracking due to SCC in the stainless steel RPV flange leak detection lines and the BMI guide tubes. It further states that the SCC in the stainless steel RPV flange leak detection lines is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. For the BMI guide tubes, LRA Section 3.1.2.2.7.1 states that they "are nickel alloy and are included with Line Item 3.1.1-31."

SRP-LR Section 3.1.2.2.7.1 states that "cracking due to SCC could occur in the PWR stainless steel reactor vessel flange leak detection lines and [BMI] guide tubes exposed to reactor coolant. The GALL Report recommends that a plant-specific AMP be evaluated to ensure that this aging effect is adequately managed."

LRA Table 3.1.2-2 credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for managing cracking due to SCC for RPV flange leak detection lines that are fabricated from stainless steel and exposed to borated water. The staff noted that the normal internal environment for the flange leak detection lines is air and the lines would be exposed to reactor coolant only when there is a leak at the inner reactor vessel closure flange O-ring. Hence, a water chemistry program is not essential because it is ineffective for mitigating SCC in stainless steel lines with stagnant coolant intermittently present. The staff concludes that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, which provides periodic inspections for leak indications to ensure the intended function of affected components will be maintained during the period of extended operation, is acceptable to manage SCC for these lines. The staff's evaluation and acceptance of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is documented in SER Section 3.0.3.1.1.

LRA Table 3.1.2-2, item 3.1.1-31 credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; the Nickel Alloy Aging Management Program; and the Water Chemistry Program for managing cracking due to SCC for BMI nozzles that are fabricated from nickel alloy and exposed to reactor coolant. For this aging effect, GALL Report item IV.A2-19 (equivalent to LRA Table 3.1.2-2, item 3.1.1-31) requires the applicant to adopt the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program and comply with applicable NRC orders with a commitment in the UFSAR supplement to implement applicable: (a) bulletins and GLs and (b) staff-accepted industry guidelines. The two AMPs required by the GALL Report are among the proposed three Salem AMPs for managing cracking due to SCC for nickel-alloy BMI nozzles. The third GALL Report requirement regarding the commitment is incorporated in the Nickel Alloy Aging Management Program and is repeated in UFSAR Supplement A.2.2.6. The staff's review and acceptance of these three AMPs are documented in SER Sections 3.0.3.1.1, 3.0.3.3.6, and 3.0.3.1.2. Therefore, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.7.1 criteria for managing the aging effect of cracking due to SCC. The staff also confirmed that the applicant's evaluation is consistent with GALL Report items IV.A2-5 and IV.A2-19.

(2) LRA Section 3.1.2.2.7.2 addresses the aging management of cracking due to SCC of CASS Class 1 piping and piping components exposed to reactor coolant. LRA

Table 3.1.1, item 3.1.1-24 also refers to LRA Section 3.1.2.2.7.2 and addresses the applicant's aging management of SCC in the CASS components. The applicant stated that the aging effect will be managed by implementing the Water Chemistry Program and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. The applicant also addressed the further evaluation requirements by indicating that the existing program relies on control of water chemistry to mitigate SCC and that SCC could occur for CASS components that do not meet the NUREG-0313 guidelines with regard to carbon content and ferrite content. The applicant further indicated that the GALL Report recommends further evaluation of a plant-specific program for these components, which do not meet NUREG-0313 guidelines, to ensure that this aging effect is adequately managed.

The staff reviewed LRA Section 3.1.2.2.7.2 against the criteria in SRP-LR Section 3.1.2.2.7, item 2, which state that cracking due to SCC could occur in CASS Class 1 PWR RCS piping, piping components, and piping elements exposed to reactor coolant. The SRP-LR recommends control of water chemistry to mitigate SCC. The SRP-LR also recommends further evaluation of a plant-specific program for these components to ensure that the aging effect is adequately managed. The GALL Report, under item IV.C2-3 (R-05), recommends monitoring and control of primary water chemistry and material selection according to NUREG-0313, Revision 2 guidelines which recommend carbon content not greater than 0.035 percent and ferrite content not less than 7.5 percent for the resistance of CASS to SCC. The GALL Report also recommends that a plant-specific AMP be further evaluated for other CASS components that do not meet these criteria.

In its review, the staff noted the applicant credited the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program to manage SCC of the CASS components under the further evaluation of LRA Section 3.1.2.2.7.2. The staff also noted that LRA Section B.2.1.6 states that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is consistent with GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," with no exception or enhancement. LRA Section B.2.1.6 also indicates that the applicant's program includes the inspections, flaw evaluations, and repairs and replacements in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. However, the staff noted that the material screening criteria used to manage the thermal aging embrittlement of CASS, as described in GALL AMP XI.M12, are different from the material screening criteria used to further evaluate and manage the SCC of CASS as described under GALL Report item IV.C2-3.

The staff noted that in order to manage the SCC of CASS under GALL Report item IV.C2-3, the GALL Report recommends further evaluation for CASS that has carbon content greater than 0.035 percent or ferrite content less than 7.5 percent. In contrast, the material screening criteria of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program are based on the combinations of molybdenum content, different threshold levels of ferrite content (14 percent and 20 percent), and casting methods (static casting and centrifugal casting). Therefore, the staff found the need to clarify how the applicant's material screening criteria used to further evaluate and manage the SCC of CASS and applicant's aging management method are consistent with the GALL Report.

By letter dated August 9, 2010, the staff issued RAI 3.1.2.2.7.2-01 requesting that the applicant clarify how the applicant's material screening criteria used to further evaluate and manage the SCC are consistent with GALL Report item IV.C2-3 which recommends that SCC of CASS with carbon content greater than 0.035 percent or ferrite content less than 7.5 percent be further evaluated and adequately managed. In the RAI, the staff also requested that the applicant clarify whether the SCC of the CASS components is managed by the inspections, flaw evaluations, and repairs and replacements in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff further requested that, if the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is not used to manage the aging effect, the applicant justify why its program is adequate to manage the aging effect.

In its response to the RAI, dated September 7, 2010, the applicant stated that the material criteria used to further evaluate and manage the aging effect and mechanism of cracking due to SCC of CASS Class 1 components are consistent with GALL Report item IV.C2-3. The applicant also stated that it reviewed the chemical compositions of the CASS components exposed to reactor coolant and it was determined that these CASS components do not meet the NUREG-0313 guidelines. The applicant further indicated that GALL Report item IV.C2-3 recommends a plant-specific AMP is to be evaluated for CASS components that do not meet the NUREG-0313 guidelines of carbon content of less than or equal to 0.035 percent and ferrite content of greater than or equal to 7.5 percent. In addition, the applicant indicated that LRA Table 3.1.2-1 inappropriately credited the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program as the plant-specific program and that instead the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be credited to manage cracking due to SCC for the CASS Class 1 components exposed to reactor coolant.

The applicant also stated that in LRA Table 3.1.2-1, the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is appropriately credited to manage the aging effect and mechanism of loss of fracture toughness due to thermal aging embrittlement. The applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program uses inspections, flaw evaluations, and repairs and replacements, as required. The applicant further indicated that LRA Table 3.1.1, item 3.1.1-24; LRA Table 3.1.2-1; and LRA Section 3.1.2.2.7.2 are revised as a result of the RAI response.

Based on its review, the staff finds the applicant’s response to RAI 3.1.2.2.7.2-01 acceptable because the applicant clarified that: (a) the material screening criteria used to manage the SCC are consistent with the GALL Report, and (b) the revised LRA credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, which is adequate to detect and manage the effects of SCC through the inspections, flaw evaluations, and repair and replacement activities. The staff’s concerns described in RAI 3.1.2.2.7.2-01 are resolved.

The staff reviewed the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the staff’s evaluations are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.1, respectively. In its review, the staff finds the applicant’s use of the Water Chemistry Program acceptable to manage the aging effect because: (a) the monitoring and controlling of water chemistry are performed periodically in accordance with the EPRI PWR water chemistry guidelines as recommended by GALL AMP XI.M2, and (b) the chemistry control minimizes the concentrations of detrimental contaminants and mitigates the occurrence of SCC in the components. In addition, the staff finds the applicant’s use of the ASME Section XI

Inservice Inspection, Subsections IWB, IWC, and IWD Program acceptable to manage the aging effect because: (a) the applicant clarified that the applicant's material screening criteria used to further evaluate and manage SCC are consistent with the GALL Report; (b) the applicant's program includes periodic inspections, flaw evaluations, and repair and replacement activities in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; (c) the periodic inspections for CASS components ensure timely detection of cracks; (d) the evaluations for detected flaws ensure that the intended functions of the components are adequately maintained for the period of extended operation; and (e) the repair and replacement activities provide adequate corrective actions for the aging management. In its review, the staff finds that the applicant's AMR results are consistent with GALL Report item IV.C2-3 and the applicant satisfied the acceptance criteria in SRP-LR Section 3.1.2.2.7.2.

Based on the programs identified above, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.1.2.2.7. For those line items that apply to LRA Section 3.1.2.2.7, 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).

3.1.2.2.8 Cracking Due to Cyclic Loading

The staff reviewed LRA Section 3.1.2.2.8 against the criteria in SRP-LR Section 3.1.2.2.8.

(1) LRA Section 3.1.2.2.8 addresses cracking due to cyclic loading stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.1.2.2.8 states that cracking due to cyclic loading may occur in the stainless steel BWR jet pump sensing lines.

The staff verified that SRP-LR Section 3.1.2.2.8, item 1 is not applicable to the Salem units because they are PWRs and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with stainless steel jet pump sensing lines.

(2) LRA Section 3.1.2.2.8 addresses cracking due to cyclic loading stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.1.2.2.8 states that cracking due to cyclic loading may occur in steel and stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff verified that SRP-LR Section 3.1.2.2.8, item 2 is not applicable to the Salem units because they are PWRs and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with isolation condensers.

Based on the above, the staff concludes that SRP-LR Section 3.1.2.2.8 criteria do not apply to Salem.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

The staff reviewed LRA Section 3.1.2.2.9 against the criteria in SRP-LR Section 3.1.2.2.9.

LRA Section 3.1.2.2.9 addresses loss of preload due to stress relaxation in stainless steel and nickel-alloy PWR RPV components exposed to reactor coolant and neutron flux as an aging effect that the applicant will manage, consistent with the SRP-LR, by the commitment of the PWR Vessel Internals Program.

SRP-LR Section 3.1.2.2.9 states that:

> Loss of preload due to stress relaxation could occur in stainless steel and nickel alloy PWR reactor vessel internals screws, bolts, tie rods, and holddown springs exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant provides a commitment in the [U]FSAR Supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

As described in LRA Section 3.1.2.2.9, the applicant made a commitment to incorporate all three GALL Report requirements stated above to manage this aging effect. The PWR Vessel Internals Program contains this commitment (Commitment No. 7). Commitment No. 7 is also identified in UFSAR Section A.2.1.7. Therefore, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.9 criteria for managing the aging effects due to loss of preload due to stress relaxation. The staff also examined LRA Table 3.1.2-3 to find out whether the RPV internals subjected to these aging effects are consistent with those listed in GALL Report Table IV.B2. The staff confirmed that LRA Table 3.1.2-3 identified all GALL Report Table IV.B2 items and the components under them for this aging effect (IV.B2-5, IV.B2-14, IV.B2-25, IV.B2-33, and IV.B2-38). For GALL Report item IV.B2-5, the applicant identified the bolts and dowels of the thermal shield as the component which is different but consistent with this GALL Report item for material, environment, and aging effect. For three of the remaining four GALL Report Table IV.B2 items, LRA Table 3.1.2-3 provides a set of subcomponents to represent a single component in GALL Report Table IV.B2. The applicant's approach of including additional components under the required AMP for GALL Report item IV.B2-5 is acceptable.

Based on a review of the program identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.9 criteria. For those line items that apply to LRA Section 3.1.2.2.9, 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).

3.1.2.2.10 Loss of Material Due to Erosion

The staff reviewed LRA Section 3.1.2.2.10 against the criteria in SRP-LR Section 3.1.2.2.10.

LRA Section 3.1.2.2.10, associated with LRA Table 3.1.1, item 3.1.1-28, addresses loss of material due to erosion in steel SG feedwater impingement plates and supports exposed to secondary feedwater. The applicant stated that this item is not applicable because steel SG feedwater impingement plates and supports do not exist in the SGs. The staff reviewed UFSAR

Section 5 and noted that the applicant's SGs do not contain steel SG feedwater impingement plates and supports and, therefore, finds the applicant's claim acceptable.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11. LRA Section 3.1.2.2.11 addresses cracking due to flow-induced vibration by stating that this aging effect is not applicable to the Salem units, which are PWRs. SRP-LR Section 3.1.2.2.11 states that cracking due to flow-induced vibration could occur for the BWR stainless steel steam dryers exposed to reactor coolant.

The staff finds that SRP-LR Section 3.1.2.2.11 is not applicable to the Salem units because they are PWRs and the staff guidance in this SRP-LR Section is only applicable to the design of steam dryers in BWR-designed reactors.

Based on the above, the staff concludes that the guidance in SRP-LR Section 3.1.2.2.11 does not apply to Salem.

3.1.2.2.12 Cracking Due to Stress-Corrosion Cracking and Irradiation-Assisted Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.12 against the criteria in SRP-LR Section 3.1.2.2.12. LRA Section 3.1.2.2.12 addresses cracking due to SCC and IASCC in stainless steel RPV internals exposed to reactor coolant and neutron flux as an aging effect that the applicant will manage, consistent with the SRP-LR, by the Water Chemistry Program and the commitment of the PWR Vessel Internals Program. SRP-LR Section 3.1.2.2.12 states that:

> Cracking due to SCC and IASCC could occur in PWR stainless steel reactor internals exposed to reactor coolant. The existing program relies on control of water chemistry to mitigate these effects. The GALL Report recommends no further AMR if the applicant provides a commitment in the [U]FSAR Supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

As indicated in SER Section 3.0.3.1.2, the staff accepts the Water Chemistry Program for mitigating the aging effects due to SCC and IASCC, meeting one of the requirements mentioned in SRP-LR Section 3.1.2.2.12. Furthermore, as described in LRA Section 3.1.2.2.12, the applicant made a commitment to incorporate all three GALL Report requirements stated above to manage this aging effect (IV.B2-2, IV.B2-8, IV.B2-10, IV.B2-12, IV.B2-24, IV.B2-30, IV.B2-36, and IV.B2-42). For GALL Report items IV.B2-10 and IV.B2-30, the applicant identified additional RPV internal components which are different but consistent with these GALL Report items for material, environment, and aging effect. For most of the GALL Report items mentioned above, LRA Table 3.1.2-3 provides a set of subcomponents to represent a single component in GALL Report Table IV.B2. The applicant's approach of including additional components under the required AMP for GALL Report items IV.B2-10 and IV.B2-30 is conservative and acceptable. However, the staff found that LRA Table 3.1.2-3 does not distinguish the aging effect discussed in this SER Section from that in LRA Section 3.1.2.2.17, "Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking." Therefore, the staff issued RAI 3.1.2.2.12-1 requesting that the applicant provide a revised LRA Table 3.1.2-3 to identify the aging effect discussed in LRA Section 3.1.2.2.17, or justify combining LRA Sections 3.1.2.2.12 and 3.1.2.2.17 under the table column title "Aging Effect Requiring Management" in LRA Table 3.1.2-3.

Although the response, dated July 15, 2010, to RAI 3.1.2.2.12-1 did not provide direct justification, the staff determines that the proposed industry program for managing PWR internals as documented in MRP-227 is structured around components, not around aging effects. Therefore, not identifying PWSCC as an aging effect for certain components in LRA Table 3.1.2-3 has no impact on the AMP to be implemented for managing PWR internals. MRP-227 is currently under the NRC's review in a separate effort. Hence, RAI 3.1.2.2.12-1 is resolved.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.12 criteria. For those line items that apply to LRA Section 3.1.2.2.12, 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).

3.1.2.2.13 Cracking Due to Primary Water Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.13 against the criteria in SRP-LR Section 3.1.2.2.13, which recommends no further AMR if the applicant complies with applicable NRC orders and provides a commitment in the UFSAR supplement to implement applicable: (1) bulletins and GLs and (2) staff-accepted industry guidelines. The staff noted that the applicant's commitment (Commitment No. 46) in LRA Appendix A, Section A.5 commits to the implementation of the Nickel Alloy Aging Management Program and that various portions of that program contain language which is consistent with the commitment described in SRP-LR Section 3.1.2.2.13. The staff also notes that all of the AMR results lines that refer to Table 3.1.1, item 3.1.1-31 are aligned with the applicant's commitment as described in LRA Appendix A, Section A.5. The staff finds the applicant's proposal acceptable because the applicant provided the appropriate commitment in the UFSAR supplement and the AMR results lines refer to the commitment.

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

LRA Section 3.1.2.2.14 refers to Table 3.1.1, item 3.1.1-32 and addresses the steel SG feedwater inlet ring and supports exposed to treated water, which are being managed for wall thinning due to flow-accelerated corrosion by the Steam Generator Tube Integrity Program. In LRA Table 3.1.1, item 3.1.1-32 and LRA Section 3.1.2.2.14, the applicant stated that the Steam Generator Tube Integrity Program will be used to manage wall thinning in the feedwater inlet ring and supports. The applicant further stated that the Steam Generator Tube Integrity Program implements a number of industry guidelines and incorporates a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures to assure that existing environmental conditions are not causing wall thinning that could result in loss of component intended function.

The staff reviewed LRA Section 3.1.2.2.14 against the criteria in SRP-LR Section 3.1.2.2.14, which state that wall thinning due to flow-accelerated corrosion could occur in the steel feedwater inlet rings and supports. The GALL Report refers to NRC IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," for evidence of flow-accelerated corrosion in SGs and recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting wall thinning due to flow-accelerated corrosion.

The staff reviewed the applicant's Steam Generator Tube Integrity Program and its evaluation is documented in SER Section 3.0.3.1.8. In its review of components associated with LRA item 3.1.1-32, the staff noted that the GALL Report recommends that a plant-specific AMP be evaluated and the applicant credits the Steam Generator Tube Integrity Program to manage wall thinning in these components.

The staff noted that the Steam Generator Tube Integrity Program description in LRA Section B.2.1.10 states that the program includes managing the aging effect of wall thinning. However, the LRA does not describe what inspection or analytical techniques are used to ensure that excessive wall thinning in components does not occur.

By letter dated June 29, 2010, the staff issued RAI 3.1.2.2.14-01 requesting that the applicant describe its examination techniques and evaluation methodology used to manage wall thinning in the SG feedwater inlet rings and supports.

In its response to the RAI, dated July 28, 2010, the applicant stated that the Steam Generator Tube Integrity Program uses visual inspections of the SGs' secondary-side internals and that it does not include predictive analytical techniques. The applicant further stated that the Unit 1 SGs are Westinghouse Model F, with feedwater rings and supports constructed of carbon steel, and that the Unit 2 SGs are AREVA Model 61/19T, with feedwater ring supports constructed of low-alloy steel plates and feedwater rings constructed of 316L stainless steel. The applicant also stated that the aging effect and mechanism of wall thinning due to flow-accelerated corrosion does not apply to the stainless steel Unit 2 SG feedwater ring.

The applicant stated that the visual inspection techniques and associated acceptance criteria are determined by a SG degradation assessment which evaluates internal and external operating experience, industry guidance, design features, and materials of construction. The applicant stated that these inspections identify the general condition of the applicable SG components and inspect for evidence of erosion-corrosion, irregular geometry, and structural changes and that the acceptance criteria require that there be no visible signs of deterioration in the Unit 1 feedwater rings or in the Units 1 and 2 feedwater ring supports. The applicant further stated that it performs an operational assessment in accordance with NEI 97-06, "Steam Generator Program Guidelines," and applicable EPRI documents to confirm that acceptance criteria are met for the SGs to return to service and operate for the subsequent cycle and that the operational assessment ensures that deficiencies are identified and corrective actions are taken before loss of component intended function occurs. The applicant also stated that while preparing its response, it noted that LRA Table 3.1.2-4, "Summary of Aging Management Evaluations for SGs," did not correctly include the material differences between Unit 1 feedwater rings (carbon steel) and Unit 2 feedwater rings (stainless steel). The applicant revised this table to show that wall thinning due to flow-accelerated corrosion is applicable for the Unit 1 carbon steel feedwater rings and for the Units 1 and 2 carbon steel or low-alloy steel supports, but is not applicable for the Unit 2 stainless steel feedwater rings. In subsequent letters dated August 26, 2010, and October 8, 2010, the applicant further revised LRA Table 3.1.2-4 to state that its SG designs include both carbon steel and stainless steel secondary internals and that wall thinning due to flow-accelerated corrosion is also applicable for the carbon steel SG secondary internals. The applicant stated that these carbon steel and low-alloy steel components are in a treated water environment (secondary feedwater/steam) and the aging effect will be managed by the Steam Generator Tube Integrity Program. The applicant also added lines showing that loss of material due to pitting and crevice corrosion and cracking due to SCC are aging effects applicable for the Unit 2 stainless steel feedwater rings. These stainless steel components are in a treated water environment and those aging effects will be managed by a combination of the Water Chemistry Program and the Steam Generator Tube Integrity Program.

In its review of the applicant's response, the staff noted that GALL AMP XI.M19, "Steam Generator Tube Integrity," references NEI 97-06. The staff determined that NEI 97-06 provides acceptable guidance for inspection and assessment of additional SG components, including the feedwater rings, supports, and secondary internals, consistent with the GALL Report. The staff further noted that industry operating experience supports the applicant's claim that flow-accelerated corrosion is not applicable to the Unit 2 stainless steel feedwater rings and the secondary internals. The staff finds the Steam Generator Tube Integrity Program acceptable to manage aging of the Unit 1 carbon steel feedwater rings and supports, the Unit 2 low-alloy steel feedwater ring supports, and the carbon steel secondary internals because the program: (1) provides visual inspections of the subject SG components based on recommendations of NEI 97-06, (2) includes assessments of inspection results against appropriate acceptance criteria, and (3) provides for corrective actions to be taken, as needed, to ensure that the subject components remain capable of performing their intended functions between scheduled SG inspections.

The staff finds the applicant's change to LRA Table 3.1.2-4 acceptable because these changes: (1) document the material difference between the steel feedwater rings in Unit 1 and the stainless steel feedwater rings in Unit 2 and (2) for the stainless steel feedwater rings and secondary internals, the staff has determined that the applicant's AMR results are acceptable as documented in SER Sections 3.4.2.2.6 and 3.4.2.2.7 for LRA Table 3.4.1, items 3.4.1-14 and 3.4.1-16, respectively.

Based on its review, the staff finds the applicant's response to RAI 3.1.2.2.14-01 acceptable as described above. The staff's concern described in RAI 3.1.2.2.14-01 is resolved.

Based on the program identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.14 criteria. For those line items that apply to LRA Section 3.1.2.2.14, 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).

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

The staff reviewed LRA Section 3.1.2.2.15 against the criteria in SRP-LR Section 3.1.2.2.15. LRA Section 3.1.2.2.15 addresses changes in dimensions due to void swelling in stainless steel and nickel-alloy PWR reactor internal components exposed to reactor coolant as an aging effect that the applicant will manage, consistent with the SRP-LR, by the commitment of the PWR Vessel Internals Program.

SRP-LR Section 3.1.2.2.15 states that:

> Changes in dimensions due to void swelling could occur in stainless steel and nickel alloy PWR reactor internal components exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant provides a commitment in the [U]FSAR Supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

As described in LRA Section 3.1.2.2.15, the applicant made a commitment to incorporate all three GALL Report requirements stated above to manage this aging effect. The PWR Vessel Internals Program contains this commitment (Commitment No. 7). Commitment No. 7 is also identified in UFSAR Section A.2.1.7. Therefore, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.15 criteria. The staff also examined LRA Table 3.1.2-3 to find out whether the RPV internals subjected to these aging effects are consistent with those listed in GALL Report Table IV.B2. The staff confirmed that LRA Table 3.1.2-3 identified all GALL Report Table IV.B2 items and the components under them for this aging effect (IV.B2-1, IV.B2-4, IV.B2-7, IV.B2-11, IV.B2-15, IV.B2-19, IV.B2-23, IV.B2-27, IV.B2-29, IV.B2-35, IV.B2-39, and IV.B2-41). For GALL Report items IV.B2-4, IV.B2-19, and IV.B2-29, the applicant identified additional RPV internal components which are different but consistent with these GALL Report items for material, environment, and aging effect. For most of the GALL Report Table IV.B2 items mentioned above, LRA Table 3.1.2-3 provides a set of subcomponents to represent a single component in GALL Report Table IV.B2. The applicant's approach of including additional components under the required AMP for GALL Report items IV.B2-4, IV.B2-19, and IV.B2-29 is acceptable.

Based on a review of the program identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.15 criteria. For those line items that apply to LRA Section 3.1.2.2.15, 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).

3.1.2.2.16 Cracking Due to Stress-Corrosion Cracking and Primary Water Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.16 against the criteria in SRP-LR Section 3.1.2.2.16.

(1) LRA Section 3.1.2.2.16.1 refers to Table 3.1.1, item 3.1.1-34, and addresses stainless steel and nickel-alloy reactor CRD head penetration pressure housings, which are managed for cracking due to SCC and PWSCC. The LRA states that the applicant will implement the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry programs to manage the cracking due to SCC in the stainless steel reactor CRD head penetration pressure housings.

The staff reviewed LRA Section 3.1.2.2.16.1 against the criteria in SRP-LR Section 3.1.2.2.16.1, which state that cracking due to SCC could occur on the primary coolant side of PWR steel SG upper and lower heads, tubesheets, and tube-to-tubesheet welds made or clad with stainless steel. The SRP-LR also states that cracking due to PWSCC could occur on the primary coolant side of PWR steel SG upper and lower heads, tubesheets, and tube-to-tubesheet welds made or clad with nickel alloy. The staff noted that the GALL Report recommends the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry programs to manage these aging effects. In addition, the GALL Report indicates that no further AMR of nickel alloys are required if the applicant complies with applicable NRC orders and provides a commitment in the UFSAR supplement to implement applicable NRC bulletins, GLs, and NRC staff-accepted industry guidelines.

The staff further reviewed the LRA and identified in Table 3.1.1, item 3.1.1-34, and Table 3.1.2-2 that the applicant addressed SCC of stainless steel reactor CRD head penetration pressure housings exposed to reactor coolant and credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry programs to manage the aging effect. The staff reviewed the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry programs and its evaluations are documented in SER Sections 3.0.3.1.1 and 3.0.3.1.2, respectively. In its review, the staff finds that the credited programs are adequate to manage the aging effect because: (a) the Water Chemistry Program monitors the plant water chemistry parameters against the established parameter limits and, if a parameter exceeds the limit, the program performs adequate actions such that the water chemistry control continues to mitigate the aging effect; (b) the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes inspections of selected components to verify the effectiveness of the Water Chemistry Program consistent with the GALL Report; and (c) the inspections in accordance with ASME Code Section XI can ensure that significant degradation does not occur and the intended function of the component is maintained during the period of extended operation consistent with the GALL Report.

In LRA Table 3.1.1, the applicant further stated that item 3.1.1-35 is not applicable because Salem Units 1 and 2 SGs are not a once-through design and, therefore, do not have the components associated with this model of SGs. The staff noted that the GALL Report, Revision 1, Volume 2 indicates that item 3.1.1-35 is only applicable to OTSGs, but not to recirculating SGs.

UFSAR Section 5.5.2.2.2 describes Unit 1 Model F SG tubes as fabricated from Alloy 600TT and welded to the Inconel cladding on the primary face of the tube plate. UFSAR Section 5.5.2.2.1 describes Unit 2 replacement SG tubes as fabricated from Alloy 690TT and weld clad with Alloy 600 at the primary side of the tubesheet.

The staff noted that ASME Code Section XI does not require any inspection of the tube-to-tubesheet welds. In addition, no specific NRC orders or bulletins require examination of this weld. However, the staff's concern is that, if the tubesheet cladding is Alloy 600, the autogenous tube-to-tubesheet weld may not have sufficient Chromium content to prevent initiation of PWSCC, even when the SG tubes are made from Alloy 690TT, as it is the configuration for the applicant's Unit 2 SG tubes. Consequently, such a PWSCC crack initiated in this region, close to a tube, could propagate into/through the weld, causing a failure of the weld and of the RCPB, even for recirculating SGs such as those for both units. Therefore, unless the NRC has approved a redefinition of the pressure boundary in which the autogenous tube-to-tubesheet weld is no longer included, or the tubesheet cladding and welds are not susceptible to PWSCC, the staff considers that the effectiveness of the primary water chemistry program should be verified to ensure PWSCC does not occur.

By letter dated November 4, 2010, the staff issued RAI 3.1.1-03 requesting that the applicant clarify for Unit 1 SGs whether the tube-to-tubesheet welds are included in the RCPB or if alternate repair criteria (ARC) have been permanently approved. Furthermore, the staff noted that if there is no ARC permanently approved, the applicant should provide a plant-specific AMP that will complement the primary water chemistry program in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds. For Unit 2 SGs tube-to-tubesheet welds, the staff requested that the applicant provide either a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds, or provide a rationale for why such a program is not needed. The staff identified this as Open Item OI 3.1.2.2.16-1.

In its response dated December 1, 2010, and revised by its letter dated December 15, 2010, the applicant committed to the following:

> [It] will develop a plan for each Unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds. Each plan will consist of two options.

The applicant committed in Commitment No. 51 to develop a plan for each unit before the period of extended operation. Each plan consists of two options.

For Unit 1, the applicant stated that the TSs were amended on March 29, 2010 (ADAMS Accession No. ML100570452), approving a one-time change to TS Section 6.8.4.i, "Steam Generator Program." The applicant explained that this amendment is an approval for ARC and limits the required inspection (and repair if degradation is found) to the portions of the SG tubes passing through the upper 13.1 inches of the approximate 21-inch tubesheet region; therefore, the bottom 7.9 inches of the tube, including the tube-to-tubesheet weld, are not presently considered part of the RCPB. The applicant further stated that the TS amendment, used in the spring 2010 refueling outage, is valid until the next scheduled SG tube inspections presently scheduled for the spring 2013 refueling outage. Since this ARC approval expires by the spring 2013 refueling outage, which is prior to the Unit 1 period of extended operation, the applicant stated that it would develop a plan to address potential cracking of the SG primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds consisting of the following two options:

In the first option, the applicant stated that it would request permanent NRC approval for ARC, which re-defines the RCPB to no longer include the autogenous tube-to-tubesheet welds prior to the Unit 1 period of extended operation. The applicant further stated that if permanent approval for ARC has not been granted by the NRC prior to Unit 1 entering its period of extended operation, it would implement the second option.

In the second option, the applicant stated that it would perform a one-time inspection of a representative number of tube-to-tubesheet welds in each of the four SGs to determine if PWSCC is present and verify the effectiveness of the Water Chemistry Program. The applicant also stated that if weld cracking is identified, the condition would be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program would be established to perform routine tube-to-tubesheet inspections for the remaining life of the SGs.

Moreover, the applicant stated that the SG tube-to-tubesheet welds have been in service for approximately 12 years since the Unit 1 SGs were replaced in April 1998. The applicant further stated that these inspections would be performed between April 2018 and April 2023, such that the SGs will have been in service between 20 and 25 years.

For Unit 2, the applicant stated that the plan would also address potential failure of the SG RCPB due to PWSCC of tube-to-tubesheet welds and would consist of the following two options:

In the first option, the applicant stated that it would perform an analytical evaluation of the SG tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary such that the autogenous tube-to-tubesheet weld is no longer included and, therefore, not required for the RCPB function. The applicant further stated that the redefinition of the RCPB would be submitted as part of a license amendment request requiring approval from the NRC, and the approved analytical evaluation would supersede the need to develop a plant-specific AMP to verify the effectiveness of the Water Chemistry Program.

In the second option, the applicant stated that it would perform a one-time inspection of a representative number of tube-to-tubesheet welds in each of the four SGs to determine if PWSCC is present and verify the effectiveness of the Water Chemistry Program. The applicant also stated that if weld cracking is identified, the condition would be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program would be established to perform routine tube-to-tubesheet inspections for the remaining life of the SGs.

Moreover, the applicant stated that the SG tube-to-tubesheet welds for Unit 2 have been in service for less than 3 years since the SGs had been replaced in April 2008. The applicant further stated that these inspections would be performed between April 2028 and April 2033, such that the SGs will have been in service between 20 and 25 years.

Based on its review, the staff finds the applicant‘s response to RAI 3.1.1-03 and associated Commitment No. 51 acceptable because the applicant will manage the aging effect of cracking due to PWSCC in the SG tube-to-tubesheet welds either by demonstrating that those welds are no longer required for the SG RCPB function (or not susceptible to PWSCC for Unit 2), or by implementing a one-time inspection on a representative number of tube-to-tubesheet welds of each SG to determine if PWSCC is present, in a time period consistent with the detection of potential PWSCC cracks. The staff finds that the timing of this inspection for each unit is acceptable because at the time of the inspections, the respective SGs will have been in operation for between 20 and 25 years, and it is unlikely that significant detrimental PWSCC cracking will have initiated. The staff also noted that, in case the aging effect is identified, this one-time inspection would be accompanied by corrective actions, including an evaluation of the degradation and the implementation of routine inspections of the tube-to-tubesheet welds for the remaining life of the SGs. The staff’s concern described in RAI 3.1.1-03 is resolved, and Open item OI 3.1.2.2.16-1 is closed.

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).

(2) LRA Section 3.1.2.2.16.2 refers to Table 3.1.1, item 3.1.1-36 and addresses the SCC in the stainless steel pressurizer spray head exposed to reactor coolant. The LRA further states that it will implement the Water Chemistry Program and One-Time Inspection Program to manage the aging effect.

The staff reviewed LRA Section 3.1.2.2.16.2 against the criteria in SRP-LR Section 3.1.2.2.16.2, which state that cracking due to SCC could occur on stainless steel pressurizer spray heads. The SRP-LR also states that the existing program relies on control of water chemistry to mitigate this aging effect. The SRP-LR further states that the GALL Report recommends a one-time inspection to confirm that the cracking does not occur. The staff also noted that the GALL Report, item IV.C2-17, recommends the Water Chemistry Program and the One-Time Inspection Program to manage the aging effect of stainless steel components. The staff noted that the GALL Report recommends the One-Time Inspection Program to verify the effectiveness of the water chemistry control program.

The staff reviewed the LRA and identified in Table 3.1.1, item 3.1.1-36, and Table 3.1.2-1 that the applicant credited the Water Chemistry and One-Time Inspection programs to manage the SCC in the stainless steel pressurizer spray head exposed to reactor coolant. The staff also reviewed the applicant's Water Chemistry and One-Time Inspection programs and its evaluations are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The applicant indicated that the One-Time Inspection Program includes a one-time inspection of more susceptible materials in potentially more aggressive environments to manage the aging effect. The staff finds that the credited programs are adequate to manage the aging effect because: (a) the Water Chemistry Program monitors the plant water chemistry control parameters against the established parameter limits and, if a parameter exceeds the limit, the program performs adequate actions such that the water chemistry control continues to mitigate the aging effect; (b) the One-Time Inspection Program includes a one-time inspection of selected components to verify the effectiveness of the Water Chemistry Program consistent with the GALL Report; and (c) the one-time inspection can ensure that significant degradation does not occur and the component's intended function is maintained during the period of extended operation. On the basis of its review, the staff finds that the applicant's AMR results are consistent with those under GALL Report, Volume 2, item IV.C2-17 and the applicant satisfied the acceptance criteria in SRP-LR Section 3.1.2.2.16.2.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.16 criteria. For those items that apply to LRA Section 3.1.2.2.16, 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).

3.1.2.2.17 Cracking Due to Stress-Corrosion Cracking, Primary Water Stress-Corrosion Cracking, and Irradiation-Assisted Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.17 against the criteria in SRP-LR Section 3.1.2.2.17. LRA Section 3.1.2.2.17 addresses cracking due to SCC, PWSCC, and IASCC in stainless steel and nickel-alloy PWR reactor internal components exposed to reactor coolant and neutron flux as an aging effect that the applicant will manage, consistent with the SRP-LR, with the Water Chemistry Program and the commitment of the PWR Vessel Internals Program.

SRP-LR Section 3.1.2.2.17 states that:

> Cracking due to SCC, PWSCC, and IASCC could occur in PWR stainless steel and nickel alloy reactor vessel internals components. The existing program relies on control of water chemistry to mitigate these effects. However, the existing program should be augmented to manage these aging effects for reactor vessel internals components. The GALL Report recommends no further AMR if the applicant provides a commitment in the [U]FSAR Supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

As indicated in SER Section 3.0.3.1.2, the staff accepts the Water Chemistry Program for mitigating the aging effects due to SCC, PWSCC, and IASCC, meeting one of the requirements mentioned in SRP-LR Section 3.1.2.2.17. Furthermore, the applicant made a commitment to incorporate all three GALL Report requirements stated above to manage this aging effect. The PWR Vessel Internals Program contains this commitment (Commitment No. 7). Commitment No. 7 is also identified in UFSAR Section A.2.1.7. Therefore, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.17 criteria. The staff also confirmed that LRA Table 3.1.2-3 identified all GALL Report Table IV.B2 items and the components under them for this aging effect (IV.B2-16, IV.B2-20, IV.B2-28, and IV.B2-40). For GALL Report item IV.B2-20, the applicant identified additional RPV internal components which are different but consistent with these GALL Report items for material, environment, and aging effect. For most of the GALL Report Table IV.B2 items mentioned above, LRA Table 3.1.2-3 provides a set of subcomponents to represent a single component in GALL Report Table IV.B2. The applicant's approach of including additional components under the required AMP for GALL Report item IV.B2-20 is conservative and acceptable.

It was mentioned in SER Section 3.1.2.2.12 that LRA Table 3.1.2-3 does not distinguish the aging effects discussed in LRA Sections 3.1.1.1.12 and 3.1.2.2.17. This has no impact on the AMP managing the PWR internals under these two aging effects as explained in SER Section 3.1.2.2.12.

Based on a review of the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.17 criteria. For those line items that apply to LRA Section 3.1.2.2.17, 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).

3.1.2.2.18 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.1.2.3 AMR Results That Are 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 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 a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line 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 line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line 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 had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.1.2.3.1 Reactor Coolant System – Summary of Aging Management Evaluation – LRA Table 3.1.2-1

The staff reviewed LRA Table 3.1.2-1 which summarizes the results of AMR evaluations for the RCS component groups.

In LRA Tables 3.1.2-1, 3.5.2-3, and 3.5.2-4, the applicant stated that stainless steel bolting components exposed to indoor air are being managed for loss of material by the Bolting Integrity Program and loss of preload due to self-loosening by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs, or the Structures Monitoring Program. The AMR line items cite generic note H.

The staff reviewed the applicant's Bolting Integrity; ASME Section XI, Subsection IWE; 10 CFR Part 50, Appendix J; and Structures Monitoring programs and its evaluations are documented in SER Sections 3.0.3.2.2, 3.0.3.2.13, 3.0.3.1.18, and 3.0.3.2.15, respectively. The staff finds the applicant's proposed programs acceptable to manage aging for these components because: (1) each program or combination of programs has incorporated industry guidance on proper selection of bolting material and lubricants and installation practices, and (2) the programs include detailed visual inspections of bolting to detect loss of material and loss of preload.

In LRA Table 3.1.2-1, the applicant stated that copper alloy valve body components exposed to lubricating oil (internal) are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The AMR line items cite generic note H, indicating that for this item the aging effect is not in the GALL Report for this material, component, and environmental condition.

The staff reviewed all AMR result line items in the GALL Report where the component and material is copper alloy and valve body components exposed to lubricating oil (internal) and confirmed that there are no aging effect entries in the GALL Report for this component, material, and environment combination.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. The staff notes that the Lubricating Oil Analysis Program includes oil sampling and analysis for viscosity, TAN, and total water analysis. This program also performs wear particle count (WPC) analysis to identify wear metals such as iron, chromium, and lead and contaminants such as silicon, calcium, and Zn. Thus, the staff finds the applicant's Lubricating Oil Analysis and One-Time Inspection programs acceptable to manage aging for these components because: (1) the Lubricating Oil Analysis Program will monitor the quality of the oil to determine if the components succumb to wear issues, as well as identify detrimental contaminants in the fluid that would lead to loss of material; and (2) the One-Time Inspection Program will determine if the Lubricating Oil Analysis Program is effective at preventing loss of material. The analysis of the oil and visual inspections are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

The staff's evaluation for glass exposed to air with borated water leakage, air or gas-wetted, and closed-cycle cooling water with no aging effect and no AMP proposed is documented in SER Section 3.3.2.3.4.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.2 Reactor Coolant System – Reactor Vessel – Summary of Aging Management Evaluation – LRA Table 3.1.2-2

The staff reviewed LRA Table 3.1.2-2 which summarizes the results of AMR evaluations for the reactor vessel component groups.

In LRA Table 3.1.2-2, the applicant stated that for nickel-alloy nozzles exposed to air with borated water leakage, there is no aging effect and no AMP is proposed. The AMR line items cite generic note G. These line items also cite plant-specific note 3, which states that this environment is not in the GALL Report for this component and material. The note also states that nickel-alloy material located indoors and subject to an air with borated water leakage environment is not subject to aging effects beyond those experienced in a reactor coolant environment that includes cracking/SCC. The note further states that these aging effects are already accounted for and are managed by the Nickel Alloy Aging Management Program that inspects the external surfaces of the nickel-alloy materials.

The staff reviewed the associated line items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because nickel alloys are not subject to external corrosion resulting from external exposure to air with borated water leakage and because the applicant recognizes the potential for internal cracking of nickel-alloy components which are internally exposed to reactor coolant. Additionally, other aging effects addressed by the GALL Report are not known to occur in nickel alloys externally exposed to air with borated water leakage.

The staff finds the applicant's proposal acceptable because: (1) the loss of material which is known to occur to steel components exposed to air with borated water leakage does not occur when nickel alloys are externally exposed to air with borated water leakage; (2) other aging effects which are addressed by the GALL Report, such as cracking, are not known to occur when nickel alloys are externally exposed to air with borated water leakage; (3) the applicant is aware of, and is adequately managing, the aging effect of cracking which is known to occur to nickel alloys which are internally exposed to reactor coolant; and (4) the inspections conducted to identify internal cracking of these components are conducted from the external surface and would identify any aging effect that may result from external exposure of these components to air with borated water leakage.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.3 Reactor Coolant System – Reactor Vessel Internals – Summary of Aging Management Evaluation – LRA Table 3.1.2-3

The staff reviewed LRA Table 3.1.2-3 which summarizes the results of AMR evaluations for the reactor vessel internals component groups.

In LRA Table 3.1.2-3, the applicant stated that the nickel-alloy RCCA guide tube assemblies and lower internal assemblies including clevis blocks, inserts for clevis blocks, and clevis block lock keys exposed to reactor coolant and neutron flux are being managed for loss of material due to wear by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The AMR line items cite generic note H. These items also cite plant-specific note 3, which states that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is used to manage the aging effects for this component, material, and environment combination.

The staff reviewed these line items and finds that the aging effect proposed by the applicant is possible, although its occurrence is not common and the extent of aging is normally not significant. The staff also reviewed other LRA items associated with these components and found that, when all associated line items are considered, the applicant has identified all credible aging effects.

The staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is documented in SER Section 3.0.3.1.1. The staff notes that these components are subject to a variety of aging effects including cracking, loss of material due to various forms of corrosion, and changes in dimension in addition to the aging effect currently under consideration. The staff also notes that a variety of AMPs are proposed by the applicant to address these aging effects including the Water Chemistry and PWR Vessel Internals programs in addition to the AMP currently under consideration. The staff finds the applicant's proposal to manage aging using this AMP acceptable because the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is capable of detecting loss of material due to wear in this component, material, and environment combination and because the same components are being inspected for other aging effects by programs which are also capable of detecting this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.4 Reactor Coolant System – SGs – Summary of Aging Management Evaluation – LRA Table 3.1.2-4

The staff reviewed LRA Table 3.1.2-4 which summarizes the results of AMR evaluations for the SG component groups.

In LRA Table 3.1.2-4, the applicant stated that the nickel-alloy spray nozzles, tube bundle tie rod assembly and anti-vibration bars, and SG tubes exposed to internal and external treated water are being managed for loss of material due to pitting and crevice corrosion and reduction in heat transfer due to fouling by the Water Chemistry and Steam Generator Tube Integrity programs. The AMR line items cite generic note H. These line items also cite plant-specific notes 2, 5, or 6. Plant-specific note 2 states that the GALL Report does not have an AMP for loss of material/pitting and crevice corrosion for nickel alloys in a treated water (secondary feedwater/steam) environment. Plant-specific note 2 also states that the Water Chemistry and Steam Generator Tube Integrity programs will be used to manage the aging effects applicable to this component type, material, and environment combination. Plant-specific note 5 states that the aging effect/mechanism of loss of material due to pitting and crevice corrosion is not in the GALL Report for this component, material, and environment, however, it is applicable to this combination. Plant-specific note 5 also states that the Water Chemistry and Steam Generator Tube Integrity programs are used to manage the aging effects for this component, material, and environment combination. Plant-specific note 6 states that the aging effect/mechanism of reduction of heat transfer due to fouling is not in the GALL Report for this component, material, and environment, however, it is applicable to this combination. This note also states that the Water Chemistry Program and Steam Generator Tube Integrity Program are used to manage the aging effects for this component, material, and environment combination.

The staff reviewed these line items and finds that the aging effects proposed by the applicant are possible, although their occurrence is not common and the extent of aging is normally not significant, especially for the reduction of heat transfer due to fouling of SG tubes exposed to reactor coolant. The staff also reviewed other LRA items associated with these components and found that, when all associated line items are considered, the applicant has identified all credible aging effects.

The staff's evaluations of the applicant's Water Chemistry and Steam Generator Tube Integrity programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. The staff finds the applicant's proposal to manage aging using these AMPs acceptable because identical AMPs are proposed in the GALL Report for similar components in similar environments to manage cracking and because the aging effects identified by the applicant (loss of material and reduction of heat transfer due to fouling) can be readily managed by programs which are capable of identifying and managing SCC. The staff notes that one of the components, spray nozzles, appears to be outside the scope of the Steam Generator Tube Integrity Program which states that the "program is specific to [steam generator] SG tubes, plugs, sleeves, and tube supports." The staff finds this wording in the scope of the AMP to be overly limiting in that the scope also addresses the implementation of NEI 97-06 in accordance with GL 97-06. The staff finds that since the nozzles under consideration are within the scope of NEI 97-06 and GL 97-06, they are also within the scope of the AMP.

In LRA Table 3.1.2-4, the applicant stated that the nickel alloy SG tubes exposed to treated water (external) and to reactor coolant (internal) are being managed for reduction of heat transfer effectiveness due to fouling of heat transfer surfaces by the Steam Generator Tube Integrity Program and the Water Chemistry Program. The AMR line items cite generic note H. Plant-specific note 6 is also cited, which states that the aging effect/mechanism of reduction of heat transfer due to fouling is not in the GALL Report for this component, material, and environment, however, it is applicable to this combination.

The staff reviewed the associated line items in the LRA and noted that it was not clear whether the aging mechanism of fouling from the inside diameter (ID) surface of the SG tubes, which is in contact with the reactor coolant, had been detected at any U.S. nuclear plant and should be taken into account. In addition, it was unclear to the staff whether the applicant has observed any fouling of its SG tubes on their primary side, secondary side or both. Moreover, the staff noted that the applicant did not explain how the Water Chemistry Program and specifically, the Steam Generator Tube Integrity Program could manage ID fouling of the SG tubes.

During a telephone conference on August 29, 2010, between the applicant and the staff, the staff discussed why the applicant has selected the aging mechanism of fouling of the SG tubes from the inside surface and how the AMPs it credited, especially the Steam Generator Tube Integrity Program, could manage this mechanism.

Consequently, by letter dated August 26, 2010, the applicant stated that it had inappropriately added the aging effect and mechanism of loss of heat transfer due to fouling for the nickel-alloy SG tubes in the reactor coolant (internal) environment to LRA Table 3.1.2-4 and had, therefore, deleted them from LRA Table 3.1.2-4. The applicant revised its LRA Table 3.1.2-4 accordingly.

The applicant also stated that the appropriate line items in LRA Table 3.1.2-4 are maintained for the applicable aging effects and mechanisms, that is the aging effect and mechanism of loss of heat transfer due to fouling for the nickel-alloy SG tubes in the treated water (external) environment are correctly shown for both its units' SGs in LRA Table 3.1.2-4.

The staff reviewed the applicant's clarification and finds it acceptable because the applicant had selected the only pertinent aging effect of reduction of heat transfer effectiveness due to fouling of heat transfer surfaces, which occurs from outside the tube surface, as identified in NRC IN 2007-37, and managed it with the appropriate programs, consistent with industry guidelines such as EPRI PWR Water Chemistry Guidelines and NEI 97-06, "Steam Generator Program Guidelines," as recommended in GALL AMPs XI.M2 and XI.M19.

The staff's evaluations of the applicant's Water Chemistry Program and Steam Generator Tube Integrity Program are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. The staff notes that the Water Chemistry Program manages the aging effects of reduction of heat transfer and includes provisions specified by the GALL Report for the verification of proper chemistry control and aging management, such that the intended functions of plant components will be maintained during the period of extended operation for Salem. The staff also notes that the aging effects managed by the Steam Generator Tube Integrity Program include reduction of heat transfer and that this program implements industry guidelines that include a secondary-side integrity plan addressing degradations on the SG secondary side that could affect tubing, consistent with GALL AMP XI.M19. The staff finds the applicant's proposal to manage aging using the Steam Generator Tube Integrity Program and Water Chemistry Program acceptable because the applicant selected the only relevant aging effect of reduction of heat transfer effectiveness due to fouling of heat transfer surfaces from outside the SG tube surface and managed it with the appropriate GALL AMPs XI.M2 and XI.M19.

In LRA Table 3.1.2-4, the applicant stated that for nickel-alloy SG components (primary channel head drain, plug, and welds) exposed to air with borated water leakage, there is no aging effect and no AMP is proposed. The AMR line items cite generic note G. These line items also cite plant-specific note 4, which states that this environment is not in the GALL Report for this component and material. The note also states that nickel-alloy material located indoors and subject to an air with borated water leakage environment is not subject to aging effects beyond those experienced in a reactor coolant environment that includes cracking/SCC. The note further states that these aging effects are already accounted for and are managed by the Nickel Alloy Aging Management Program that inspects the external surfaces of the nickel-alloy materials.

The staff reviewed the associated line items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because nickel alloys are not subject to external corrosion resulting from external exposure to air with borated water leakage and because the applicant recognizes the potential for internal cracking of nickel-alloy components which are internally exposed to reactor coolant. Additionally, other aging effects addressed by the GALL Report are not known to occur in nickel alloys externally exposed to air with borated water leakage.

The staff finds the applicant's proposal acceptable because: (1) the loss of material which is known to occur to steel components exposed to air with borated water leakage does not occur when nickel alloys are externally exposed to air with borated water leakage; (2) other aging effects which are addressed by the GALL Report, such as cracking, are not known to occur when nickel alloys are externally exposed to air with borated water leakage; (3) the applicant is aware of, and is adequately managing, the aging effect of cracking which is known to occur to nickel alloys which are internally exposed to reactor coolant; and (4) the inspections conducted to identify internal cracking of these components are conducted from the external surface and would identify any aging effect that may result from external exposure of these components to air with borated water leakage.

In LRA Table 3.1.2-4, the applicant stated that stainless steel SG tube bundle tie rod assemblies and anti-vibration bars exposed to treated water at greater than 60 °C (140 °F) are being managed for loss of material by the Water Chemistry and Steam Generator Tube Integrity programs. The AMR line items cite generic note H.

The staff reviewed the applicant's Water Chemistry and Steam Generator Tube Integrity programs which are evaluated in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. The staff noted that the applicant's Water Chemistry Program monitors and controls the concentration of contaminants in the water in accordance with EPRI guidelines in order to mitigate loss of material. The staff also noted that the applicant's Steam Generator Tube Integrity Program includes good foreign material exclusion practices, NDE of tubes, ISI, and leakage monitoring to mitigate and detect the effects of loss of material on SG components. The staff finds the monitoring programs acceptable to manage loss of material because they include both preventive measures (i.e., water chemistry control and good foreign material exclusion practices) to prevent loss of material, as well as NDEs, visual inspections, and leakage monitoring to detect if loss of material is occurring.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the RCS, reactor vessel, reactor vessel internals, and SG components within the scope of license renewal and subject to an AMR 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).

3.2 Aging Management of Engineered Safety Features

This Section of the SER documents the staff's review of the applicant's AMR results for the ESF components and component groups of the:

- containment spray system
- residual heat removal system
- safety injection system

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF components and component groups. LRA Table 3.2.1, "Summary of Aging Management Evaluations for the Engineered Safety Features," provides a summary comparison of its AMRs to those evaluated in the GALL Report for ESF 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 issue 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 ESF components within the scope of license renewal and subject to an AMR 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 conducted an onsite audit of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified 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 had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.2.2.1 and 3.2.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.2.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line 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 (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel piping, piping components, and piping elements in the emergency core cooling system (ECCS) (3.2.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.2.2.2.1)
Steel with stainless steel cladding pump casing exposed to treated borated water (3.2.1-2)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks"	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.2)
Stainless steel containment isolation piping and components internal surfaces exposed to treated water (3.2.1-3)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.3(1))
Stainless steel piping, piping components, and piping elements exposed to soil (3.2.1-4)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.3(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (3.2.1-5)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.3(3))
Stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.2.1-6)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.3(4))
Partially encased stainless steel tanks with breached moisture barrier exposed to raw water (3.2.1-7)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottoms because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.3(5))
Stainless steel piping, piping components, piping elements, and tank internal surfaces exposed to condensation (internal) (3.2.1-8)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with the GALL Report (see SER Section 3.2.2.2.3(6))
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (3.2.1-9)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.4(1))
Stainless steel heat exchanger tubes exposed to treated water (3.2.1-10)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.2.2.2.4(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomer seals and components in the standby gas treatment system exposed to air-indoor uncontrolled (3.2.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.5)
Stainless steel high-pressure safety injection (HPSI) (charging) pump miniflow orifice exposed to treated borated water (3.2.1-12)	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.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.6)
Steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air-indoor uncontrolled (internal) (3.2.1-13)	Loss of material due to general corrosion and fouling	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.7)
Steel piping, piping components, and piping elements exposed to treated water (3.2.1-14)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.8(1))
Steel containment isolation piping, piping components, and piping elements internal surfaces exposed to treated water (3.2.1-15)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.8(2))
Steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.8(3))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil (3.2.1-17)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Not applicable	Not applicable to Salem (see SER Section 3.2.2.2.9)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.2.1-18)	Cracking due to SCC and IGSCC	BWR Stress Corrosion Cracking and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Steel piping, piping components, and piping elements exposed to steam or treated water (3.2.1-19)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) > 250 °C (482 °F) (3.2.1-20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
High-strength steel closure bolting exposed to air with steam or water leakage (3.2.1-21)	Cracking due to cyclic loading and SCC	Bolting Integrity		Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Steel closure bolting exposed to air with steam or water leakage (3.2.1-22)	Loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel bolting and closure bolting exposed to air-outdoor (external) or air-indoor uncontrolled (external) (3.2.1-23)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity	Consistent with the GALL Report
Steel closure bolting exposed to air-indoor uncontrolled (external) (3.2.1-24)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity; 10 CFR Part 50, Appendix J; and ASME Section XI, Subsection IWE	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (140 °F) (3.2.1-25)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-26)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Steel heat exchanger components exposed to closed-cycle cooling water (3.2.1-27)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.2.1-28)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.2.1-29)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Stainless steel and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.2.1-30)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
External surfaces of steel components including ducting, piping, ducting closure bolting, and containment isolation piping external surfaces exposed to air-indoor uncontrolled (external), condensation (external), and air-outdoor (external) (3.2.1-31)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with the GALL Report
Steel piping and ducting components and internal surfaces exposed to air-indoor uncontrolled (internal) (3.2.1-32)	Loss of material due to general corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Steel encapsulation components exposed to air-indoor uncontrolled (internal) (3.2.1-33)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to condensation (internal) (3.2.1-34)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel containment isolation piping and components internal surfaces exposed to raw water (3.2.1-35)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Steel heat exchanger components exposed to raw water (3.2.1-36)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-37)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Stainless steel containment isolation piping and components internal surfaces exposed to raw water (3.2.1-38)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Stainless steel heat exchanger components exposed to raw water (3.2.1-39)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel heat exchanger tubes (serviced by open-cycle cooling water) exposed to raw water (3.2.1-40)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.2.1-41)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-42)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Gray cast iron piping, piping components, and piping elements exposed to soil (3.2.1-43)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Gray cast iron motor cooler exposed to treated water (3.2.1-44)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Aluminum, copper alloy > 15% Zn and steel external surfaces, bolting, and piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-45)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel encapsulation components exposed to air with borated water leakage (internal) (3.2.1-46)	Loss of material due to general, pitting, crevice and boric acid corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
CASS piping, piping components, and piping elements exposed to treated borated water > 250 °C (482 °F) (3.2.1-47)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to Salem (see SER Section 3.2.2.1.1)
Stainless steel or stainless-steel-clad steel piping, piping components, piping elements, and tanks (including safety injection tanks/accumulators) exposed to treated borated water > 60 °C (140 °F) (3.2.1-48)	Cracking due to SCC	Water Chemistry	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.2.2.1.2)
Stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water (3.2.1-49)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Sections 3.2.2.1.3 and 3.2.2.2.3(1))
Aluminum piping, piping components, and piping elements exposed to air-indoor uncontrolled (internal/external) (3.2.1-50)	None	None	NA	None	Consistent with the GALL Report
Galvanized steel ducting exposed to air-indoor controlled (external) (3.2.1-51)	None	None	NA	None	Not applicable to Salem (see SER Section 3.2.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass piping elements exposed to air-indoor uncontrolled (external), lubricating oil, raw water, treated water, or treated borated water (3.2.1-52)	None	None	NA	None	Consistent with the GALL Report
Stainless steel, copper alloy, and nickel-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.2.1-53)	None	None	NA	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air-indoor controlled (external) (3.2.1-54)	None	None	NA	None	Not applicable to Salem (see SER Section 3.2.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.2.1-55)	None	None	NA	None	Not applicable to Salem (see SER Section 3.2.2.1.1)
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to gas (3.2.1-56)	None	None	NA	None	Consistent with the GALL Report
Stainless steel and copper alloy < 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-57)	None	None	NA	None	Consistent with the GALL Report

The staff's review of the ESF component groups followed several approaches. One approach, documented in SER Section 3.2.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.2.2.2, discusses the staff's review of AMR results for components 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, discusses the staff's review of AMR results for components 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 components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report

In LRA Section 3.2.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects of ESF components:

- Aboveground Non-Steel Tanks
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- Closed-Cycle Cooling Water System
- External Surfaces Monitoring
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Periodic Inspection
- Water Chemistry
- TLAA

LRA Tables 3.2.2-1 to 3.2.2-3 summarize AMRs for the ESF components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed a review to determine whether the plant-specific components in these GALL Report component groups were bounded by 6the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line 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 line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

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

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

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

The staff notes that in LRA Tables 3.2.2-1 and 3.2.2-3, there are AMR line items for stainless steel tanks exposed to treated water and treated borated water, respectively. The staff also notes that the LRA does not have a line item for the tank material exposed to an air or wetted gas internal environment as would occur when the tank is partially full. The staff further notes that in the case of LRA Table 3.2.2 1, the LRA line items manage the aging of the tank internals using the Water Chemistry and One-Time Inspection programs. The staff finds the existing line items acceptable because: (1) the Water Chemistry Program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, and (2) the One-Time Inspection Program will provide reasonable assurance that an aging effect is not occurring or that the aging effect is occurring slowly enough to not affect a components intended function. The staff notes that in the case of the tanks included in LRA Table 3.2.2-3, the LRA line items manage the aging of the tank internals using the Water Chemistry Program. The staff finds these existing line items acceptable because: (1) the Water Chemistry Program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, (2) the use of only the Water Chemistry Program is consistent with GALL Report item V.D1-30 and there are no other GALL Report line items in Section V.D1 related to tanks that require anything more than the Water Chemistry Program, and (3) the GALL Report recommends that there is no AERM or recommended AMP for stainless steel tanks exposed to air-indoor uncontrolled or condensation.

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).

LRA Tables 3.2.2-1 to 3.2.2-3 provide a summary of the AMR results for component types associated with the ESF. The summary information for each component type included intended function, material, environment, AERM, AMPs, GALL Report Volume 2 item, cross reference to LRA Table 3.2.1, and generic and plant-specific notes related to consistency 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, it did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs.

On the basis of its review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.2.1, the applicant's references to the GALL Report are acceptable and no further evaluation is required.

3.2.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.2.1, item 3.2.1-17 addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The applicant stated that this line item is not applicable because there are no steel piping, piping components, and piping elements buried in soil in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for ESF systems that include steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, items 18 through 20 discuss the applicant's determination on the GALL Report AMR line items that are applicable only to BWR-designed reactors. In the applicant's AMR discussions for items 18 through 20, no additional information is provided. The staff confirmed that AMR items 18 through 20, in Table 1 of the GALL Report, Volume 1, are only applicable to BWR-designed reactors and that Salem is a PWR with a dry ambient containment. Based on this determination, the staff finds that AMR items 18 through 20, in Table 1 of the GALL Report, Volume 1, are not applicable to Salem.

LRA Table 3.2.1, item 3.2.1-21 addresses high-strength steel closure bolting exposed to air with steam or water leakage in the ESF systems. The GALL Report recommends use of GALL AMP XI.M18, "Bolting Integrity," to manage cracking due to cyclic loading or SCC for this component group. The applicant stated that this item is not applicable because there is no high-strength closure bolting in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage is present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-22 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends use of GALL 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 there is no steel closure bolting exposed to air with steam or water leakage in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant’s LRA does not have any AMR results for the ESF systems that include steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant’s UFSAR and confirmed that no in-scope steel closure bolting exposed to air with steam or water leakage is present in the ESF systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.2.1, item 3.2.1-26 addresses loss of material due to general, pitting, and crevice corrosion in steel piping, piping components, and piping elements exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to closed-cycle cooling water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant’s LRA does not have any AMR results that include steel piping, piping components, or piping elements exposed to closed-cycle cooling water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope steel piping, piping components, or piping elements exposed to closed-cycle cooling water are present in the ESF systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.2.1, item 3.2.1-27 addresses loss of material due to general, pitting, crevice, and galvanic corrosion in steel heat exchanger components exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to closed-cycle cooling water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant’s LRA does not have any AMR results that include steel heat exchanger components exposed to closed-cycle cooling water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope steel heat exchanger components exposed to closed-cycle cooling water are present in the ESF systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.2.1, item 3.2.1-29 addresses loss of material due to pitting, crevice, and galvanic corrosion in copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to closed-cycle cooling water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant’s LRA does not have any AMR results that include copper piping, piping components, piping elements, or heat exchanger components exposed to closed-cycle cooling water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope copper piping, piping components, piping elements, or heat exchanger components exposed to closed-cycle cooling water are present in the ESF systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.2.1, item 3.2.1-32 addresses loss of material due to general corrosion in steel piping and ducting components and internal surfaces exposed internally to uncontrolled indoor air. The applicant stated that this line item is not applicable because the AMR methodology assumes internal surfaces are exposed to an air/gas-wetted environment, which includes condensation, and as a result, item 3.2.1-34 is credited for this component instead. The staff evaluated the applicant’s claim and found it acceptable because the applicant has credited an alternate line item (item 3.2.1-34) to manage this component group, which includes management for loss of material due to pitting and crevice corrosion, in addition to general corrosion.

LRA Table 3.2.1, item 3.2.1-33 addresses loss of material due to general, pitting, and crevice corrosion in steel encapsulation components exposed internally to uncontrolled indoor air. The applicant stated that this line item is not applicable because there are no steel encapsulation components exposed to indoor air in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include steel encapsulation components exposed internally to uncontrolled indoor air. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope steel encapsulation components exposed internally to uncontrolled indoor air are present in the ESF system and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-35 addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling for the internal surfaces of steel containment isolation piping and components exposed to raw water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results that include corresponding components exposed to raw water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope steel containment isolation piping and components exposed to raw water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-36 addresses loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling for steel heat exchanger components exposed to raw water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results that include corresponding components exposed to raw water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope steel heat exchanger components exposed to raw water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-37 addresses loss of material due to pitting, crevice, and microbiologically-influenced corrosion for stainless steel piping, piping components, and piping elements exposed to raw water. The applicant stated that this item is not applicable because the corresponding components in the safety injection system are evaluated with the service water system in Table 3.4.1, item 3.4.1-33. The staff reviewed LRA Sections 2.3.2, 2.3.4, 3.2, and 3.4 and confirmed that the corresponding components exposed to raw water in the safety injection system were evaluated through item 3.4.1-33. The staff also reviewed the UFSAR and did not identify any other in-scope stainless steel piping, piping components, or piping elements exposed to raw water in the ESF systems which were not evaluated in the LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-38 addresses loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling for the internal surfaces of stainless steel containment isolation piping and components exposed to raw water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results that include corresponding components exposed to raw water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope stainless steel containment isolation piping and components exposed to raw water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-39 addresses loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling for stainless steel heat exchanger components exposed to raw water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results that include corresponding components exposed to raw water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope stainless steel heat exchanger components exposed to raw water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-40 addresses reduction of heat transfer due to fouling for steel and stainless steel heat exchanger tubes exposed to raw water. The applicant stated that this item is not applicable because there are no corresponding components in the ESF systems exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results that include corresponding components exposed to raw water in the ESF systems. The staff also reviewed the UFSAR and confirmed that no in-scope steel or stainless steel heat exchanger tubes exposed to raw water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-41 addresses copper alloy greater than 15 percent Zn piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water. The GALL Report recommends the use of GALL AMP XI.M33, "Selective Leaching of Materials," to manage loss of material due to selective leaching for this component group. The applicant stated that this line item is not applicable because there are no ESF system components fabricated from copper alloy greater than 15 percent Zn and exposed to closed-cycle cooling water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include copper alloy greater than 15 percent Zn piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope copper alloy greater than 15 percent Zn piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water are present in the ESF systems. Based on its review of the LRA, the staff confirmed that there are no in-scope copper alloy greater than 15 percent Zn piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-42 addresses gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water. The applicant stated that this line item was not applicable. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water. The staff also noted that a search of the applicant's UFSAR did not find any evidence of gray cast iron piping, piping components, and piping elements in the ESF systems exposed to closed-cycle cooling water. Based on its review of the LRA and UFSAR, the staff confirmed that there are no in-scope gray cast iron piping, piping components, and piping elements exposed to soil in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-43 addresses gray cast iron piping, piping components, and piping elements exposed to soil. The GALL Report recommends the use of GALL AMP XI.M33, "Selective Leaching of Materials," to manage loss of material due to selective leaching for this component group. The applicant stated that this line item was not applicable because there are no ESF system piping, piping components, and piping elements fabricated from gray cast iron and exposed to soil. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include gray cast iron piping, piping components, and piping elements exposed to soil. The staff also noted that a search of the applicant's UFSAR did not find any evidence of gray cast iron piping, piping components, and piping elements in the ESF systems exposed to soil. Based on its review of the LRA and UFSAR, the staff confirmed that there are no in-scope gray cast iron piping, piping components, and piping elements exposed to soil in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-44 addresses gray cast iron motor coolers exposed to treated water. The GALL Report recommends the use of GALL AMP XI.M33, "Selective Leaching of Materials," to manage loss of material due to selective leaching for this component group. The applicant stated that this line item is not applicable because there are no ESF system motor coolers fabricated from gray cast iron and exposed to treated water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include gray cast iron motor coolers exposed to treated water. The staff also noted that a search of the applicant's UFSAR did not find any evidence of gray cast motor coolers in the ESF systems exposed to treated water. Based on its review of the LRA and the UFSAR, the staff confirmed that there are no in-scope gray cast iron motor coolers exposed to treated water in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-46 addresses loss of material due to general, pitting, crevice, and boric acid corrosion in steel encapsulation components exposed internally to air with borated water leakage. The applicant stated that this line item is not applicable because there are no steel encapsulation components exposed to air with borated water leakage in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include steel encapsulation components exposed internally to air with borated water leakage. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope steel encapsulation components exposed internally to air with borated water leakage are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-47 addresses loss of fracture toughness due to thermal aging embrittlement in CASS piping, piping components, and piping elements exposed to treated borated water greater than 250 °C (482 °F). The applicant stated that this line item is not applicable because there are no CASS piping, piping components, or piping elements subject to treated borated water greater than 250 °C (482 °F) in the ESF systems. The staff reviewed the applicant's UFSAR Table 6.3-14 which states that valves in the emergency core cooling system (ECCS) are constructed of austenitic stainless steel. The staff reviewed the applicant's LRA drawings and determined that the only CASS components that could be exposed to temperatures greater than 250 °C (482 °F) are the safety injection cold leg check valves. The safety injection cold leg check valves would prevent upstream components that could be constructed from cast austenitic materials from being exposed to temperatures greater than 250 °C (482 °F). The LRA and supplemental documents lack sufficient detail for the staff to determine if the safety injection cold leg check valves are constructed of CASS and if they are exposed to temperatures greater than 250 °C (482 °F). By letter dated August 19, 2010, the staff issued RAI 3.2.1.47-01 requesting that the applicant state whether the safety injection cold leg check valves are constructed of CASS and if they are exposed to temperatures greater than 250 °C (482 °F).

In its response dated September 7, 2010, the applicant stated that the safety injection cold leg check valves are constructed of CASS and exposed to temperatures greater than 250 °C (482 °F), and the LRA should have included GALL Report item IV.C2-6 in LRA Table 3.2.2-3 for this component type. The applicant also stated that: (1) it has revised the LRA to add the AMR line item to Table 3.2.2-3; (2) it has referenced Table 1, item 3.1.1-55; and (3) the aging effect will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

The staff finds the applicant's response acceptable because GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," states:

> For pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (NEI), screening for susceptibility to thermal aging is not required. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings and valve bodies.

The staff's concern described in RAI 3.2.1.47-01 is resolved.

LRA Table 3.2.1, item 3.2.1-51 addresses galvanized steel ducting externally exposed to controlled indoor air. The applicant stated that this line item is not applicable because the applicant does not have any galvanized steel ducting externally exposed to controlled indoor air in the ESF systems. The applicant also stated that there is no AERM or recommended AMP for this material and component combination. The staff notes that the GALL Report recommends that there is no AERM or AMP for this material and environment combination. The staff, therefore, finds that the applicant's proposal that there is no AERM or AMP acceptable regardless of whether or not the material and environment combination exists in the ESF systems.

LRA Table 3.2.1, item 3.2.1-54 addresses steel piping, piping components, and piping elements externally exposed to controlled indoor air. The applicant stated that this line item is not applicable because the applicant does not have any steel piping, piping components, and piping elements exposed to controlled indoor air in the ESF systems and all indoor air is assumed to be uncontrolled for the purposes of license renewal. The staff reviewed LRA Sections 2.3.3 and 3.2 and confirmed that the applicant's LRA does have AMR results for steel components exposed to indoor uncontrolled air and that those items are being managed by alternative line items applicable to indoor uncontrolled air. The staff finds the applicant's determination acceptable because uncontrolled air is a more aggressive environment than controlled air and the items are being managed by appropriate alternative line items.

LRA Table 3.2.1, item 3.2.1-55 addresses steel and stainless steel piping, piping components, and piping elements in concrete. The applicant stated that this line item is not applicable because the applicant does not have any steel and stainless steel piping, piping components, and piping elements exposed to concrete in the ESF systems. The applicant also stated that there is no AERM or recommended AMP for this material and component combination. The staff notes that the GALL Report recommends that there is no AERM or AMP for this material and environment combination. The staff, therefore, finds that the applicant's proposal that there is no AERM or AMP acceptable regardless of whether or not the material and environment combination exists in the ESF systems.

3.2.2.1.2 Cracking Due to Stress Corrosion Cracking

LRA Table 3.2.1, item 3.2.1-48 addresses stainless steel and steel with stainless steel cladding piping, piping components, piping elements, and tanks (including safety injection tanks/accumulators) exposed to treated borated water greater than 60 °C (140 °F) which are being managed for cracking due to stress corrosion cracking. The SRP-LR recommends that the aging be managed by GALL AMP XI.M2, "Water Chemistry." In its review of components associated with item number 3.2.1-48 for which the applicant cited generic note A, the staff noted that the existing guidance in the SRP-LR and GALL Report does not adequately address aging management for loss of material and cracking in treated borated water environments, in that, boron should not be credited as a corrosion inhibitor. In teleconference calls held with the applicant on May 5 and 10, 2011, the staff discussed draft RAI 3.2.1.48 requesting that the applicant state how the effectiveness of the Water Chemistry Program will be verified for the aging management for loss of material and cracking in treated borated water.

By letter dated May 18, 2011, the applicant provided a supplement to its LRA to include a one-time inspection to verify the effectiveness of the Water Chemistry Program in treated borated water environments.

The staff finds the LRA supplement acceptable because: (1) the effectiveness of the Water Chemistry Program will be verified to ensure that significant degradation due to stress corrosion cracking is not occurring, and (2) the additional one-time inspection activity is applied to systems that are not consistent with the PWR reactor coolant environment (e.g., low dissolved oxygen), and thus would be expected to be more prone to stress corrosion cracking.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of components associated with item 3.2.1-48, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs acceptable because: (1) the Water Chemistry 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 (2) the One-Time Inspection Program includes a one-time visual inspection which is capable of detecting stress corrosion cracking of select components to verify the effectiveness of the Water Chemistry Program.

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).

3.2.2.1.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.2.1, item 3.2.1-49 addresses stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water which are being managed for loss of material due to pitting and crevice corrosion. In its review of components associated with item number 3.2.1-49 for which the applicant cited generic note A, the staff noted that the existing guidance in the SRP-LR and GALL Report does not adequately address aging management for loss of material and cracking in treated borated water environments, in that, boron should not be credited as a corrosion inhibitor. In teleconference calls held with the applicant on May 5 and 10, 2011, the staff discussed draft RAI 3.2.1.48 requesting that the applicant state how the effectiveness of the Water Chemistry Program will be verified for the aging management for loss of material and cracking in treated borated water.

By letter dated May 18, 2011, the applicant provided a supplement to its LRA to include a one-time inspection to verify the effectiveness of the Water Chemistry Program in treated borated water environments.

The staff finds the applicant's LRA supplement acceptable because: (1) the effectiveness of the Water Chemistry Program will be verified to ensure that significant degradation due to loss of material is not occurring, and (2) the additional one-time inspection activity is applied to systems that are not consistent with the PWR reactor coolant environment (e.g., low dissolved oxygen), and thus would be expected to be more prone to loss of material.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of components associated with item 3.2.1-49, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs acceptable because: (1) the Water Chemistry 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 (2) the One-Time Inspection Program includes a one-time visual inspection which is capable of detecting loss of material of select components to verify the effectiveness of the Water Chemistry Program.

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).

3.2.2.1.4 Conclusion for AMRs Consistent with the GALL Report

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated 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 with the GALL Report AMRs. Therefore, the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

LRA Section 3.2.2.2 provides further evaluation of aging management as recommended by the GALL Report for the ESF components. The applicant provided 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
- reduction of heat transfer due to fouling
- hardening and loss of strength due to elastomer degradation
- loss of material due to erosion
- loss of material due to general corrosion and fouling
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced 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 GALL Report and for which further evaluation is recommended, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues. In addition, the staff reviewed the applicant's further evaluations against the criteria 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 states fatigue is a TLAA as defined in 10 CFR 54.3. Furthermore, TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that the evaluation of metal fatigue as a TLAA for the residual heat removal and safety injection systems is discussed in LRA Section 4.3.

The staff reviewed LRA Section 3.2.2.2.1 against the criteria in SRP-LR Section 3.2.2.2.1, which state that fatigue of ESF components is a TLAA as defined in 10 CFR 54.3 and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff also reviewed LRA Section 3.2.2.2.1 and the AMRs discussed in this Section against the staff's AMR items for evaluating cumulative fatigue damage in PWR ESF designs, as given in AMR item 1 of Table 2 of the GALL Report, Volume 1 and the AMR items in Section V of the GALL Report, Volume 2, Revision 1 that derive from this GALL Report, Volume 1 AMR item.

With regard to LRA Table 3.2.1, item 3.2.1-1, the staff noted that GALL AMR item V.D1-27 identifies cumulative fatigue damage as an applicable aging effect for steel and stainless steel piping, piping components, and piping elements in the ECCS and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included an applicable line item in LRA Tables 3.2.2-2 and 3.2.2-3 for piping and fittings that received implicit fatigue analysis calculations in accordance with design code requirements for ASME Code Section III Class 2 or 3 components or ANSI B31.1 components consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of piping and fittings acceptable because it is consistent with the recommendations in SRP-LR Section 3.2.2.2.1. The staff's evaluation of the TLAA analysis for the piping and fittings component is in SER Section 4.3.3.

Based on the programs identified, 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 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).

3.2.2.2.2 Loss of Material Due to Cladding Breach

LRA Section 3.2.2.2.2 addresses carbon steel pump casings with stainless steel cladding exposed to treated borated water. The GALL Report recommends use of a plant-specific AMP to manage the loss of material due to cladding breach for this component group. The applicant stated that this line item is not applicable because there are no comparably constructed pump casings in the ESF systems. The applicant added that only Unit 2 has carbon steel pump casings with stainless steel cladding and these are evaluated in Table 3.3.1, items 3.3.1-35 and 3.3.1-91, as part of the chemical and volume control system in the auxiliary systems section. The staff reviewed LRA Sections 2.3.3 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include carbon steel pump casings with stainless steel cladding exposed to treated borated water. The staff reviewed the applicant's UFSAR, which indicates that the charging pumps fabricated of carbon steel with stainless steel cladding are only found in Unit 2 and are included in the auxiliary systems as part of the chemical and volume control system 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 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 stainless steel containment isolation piping, piping components, and piping elements exposed to treated water. The applicant stated that this item is not applicable because the related components are exposed to treated borated water, not treated water. The applicant also stated that the internal surfaces of stainless steel piping and piping components exposed to treated borated water in the ESF systems are evaluated with Table 3.2.1, item 3.2.1-49. The staff reviewed LRA Sections 2.3.2 and 3.2 and noted that LRA Table 3.3.2-1 for the

containment spray system contained comparable components in a treated water environment, but these items were addressed in item 3.3.1-24, which is evaluated further in SER Section 3.3.2.2.10, item 2 for auxiliary systems. Otherwise, the staff confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include stainless steel containment isolation piping components and piping elements exposed to treated water. In addition, the staff noted that the GALL Report does not recommend further evaluation for components associated with Table 3.2.1, item 3.2.1-49. The staff reviewed the applicant's UFSAR and, other than noted above for the containment spray system, confirmed that no in-scope stainless steel containment isolation piping, piping components, and piping elements exposed to treated water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

(2) LRA Section 3.2.2.2.3.2 refers to Table 3.2.1, item 3.2.1-4 and addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this item is not applicable because the piping, piping components, and piping elements external surfaces in the containment spray system, residual heat removal system, and safety injection system are not exposed to soil because all of the stainless steel piping, piping components, and piping elements are inside the auxiliary building and containment structure. The applicant also stated that the refueling water storage tank in the safety injection system has a stainless steel bottom exposed to soil and the aging effect is managed by the Aboveground Non-Steel Tanks Program. The staff reviewed the LRA AMR items and information in the UFSAR associated with Table 3.2.1, item 3.2.1-4 and confirmed that there are no stainless steel piping, piping components, and piping elements exposed to soil in the ESF systems. Therefore, the staff finds the applicant's determination that LRA Table 3.2.1, item 3.2.1-4 is not applicable acceptable.

(3) LRA Section 3.2.2.2.3 addresses loss of material due to pitting and crevice corrosion and states that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur in BWR stainless steel and aluminum piping, piping components, and piping elements exposed to treated water.

This line item is not applicable to the Salem units because they are PWRs. On this basis, the staff finds that the SRP-LR criteria do not apply to Salem.

(4) LRA Section 3.2.2.2.3.4, referenced by LRA Table 3.2.1, item 3.2.1-6, addresses stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil, which are being managed for loss of material due to pitting and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant stated that this item is not applicable because there are no stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil in the ESF systems. However, the applicant stated that the safety injection system pump lube oil coolers are titanium and are evaluated with the service water system, which is an auxiliary system. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage the loss of material through examination of susceptible locations in titanium pump lube oil coolers exposed to lubricating oil in the safety injection system.

The staff reviewed LRA Section 3.2.2.2.3.4 against the criteria in SRP-LR Section 3.2.2.2.3, item 4, which state loss of material from pitting and crevice corrosion could occur for stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation to verify the effectiveness of the lubricating oil program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the UFSAR to verify that there are no stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil in the ESF systems at Salem. Instead, the applicant stated that titanium lube oil coolers are exposed to lubricating oil and are components in an ESF system (i.e., safety injection system).

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.2.1-6, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (1) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (2) the applicant stated that the One-Time Inspection Program will be used to examine titanium pump lube oil coolers to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.2.2.2.3, item 4 and, therefore, the applicant's AMR is consistent with GALL Report items V.A-21, V.D1-18, and V.D1-24.

Based on information in the UFSAR, the staff confirmed that the applicant's plant does not have stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil in the ESF systems. Therefore, the staff finds that this item is not applicable. Instead, titanium lube oil coolers are exposed to lubricating oil and are components in an ESF system (i.e., safety injection system). The staff reviewed this AMR and concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3, item 4 criteria. For the line items that apply to LRA Section 3.2.2.2.3.4, 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).

(5) LRA Section 3.2.2.2.3, item 5, associated with LRA Table 3.2.1, item 3.2.1-7, addresses loss of material from pitting and crevice corrosion in partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering. The applicant stated that this line item is not applicable because there are no partially encased stainless steel tanks with breached moisture barrier exposed to raw water in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and confirmed that no in-scope partially encased stainless steel tanks exposed to raw water

due to cracking of the perimeter seal from weathering are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

(6) LRA Section 3.2.2.2.3, item 6 is referenced by LRA Table 3.2.1, item 3.2.1-8 and addresses stainless steel piping, piping components, and piping elements exposed to wetted air and gas which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the subject components exposed to the subject environment in the containment spray system will be managed by the Periodic Inspection Program, which manages the aging effects of components not covered by other AMPs. The applicant also stated that the Periodic Inspection Program includes visual inspections and volumetric examinations to assure that material degradation does not result in a loss of component intended function.

Based on a review of the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3 criteria. For those line items that apply to LRA Section 3.2.2.2.3, 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).

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.2.2.2.4 against the criteria in SRP-LR Section 3.2.2.2.4.

(1) LRA Section 3.2.2.2.4.1, referenced by LRA Table 3.2.1, item 3.2.1-9, addresses steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil, which are being managed for reduction of heat transfer due to fouling by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant stated that this item is not applicable to the ESF systems because there are no steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. However, the applicant stated that the safety injection system pump lube oil coolers are titanium and are evaluated with the service water system. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage the loss of material through examination of susceptible locations in titanium pump lube oil coolers exposed to lubricating oil in the safety injection system.

The staff reviewed LRA Section 3.2.2.2.4.1 against the criteria in SRP-LR Section 3.2.2.2.4, item 1, which state that reduction of heat transfer due to fouling could occur for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on monitoring and control of lube oil chemistry to mitigate reduction of heat transfer due to fouling. The SRP-LR further states that control of lube oil chemistry may not always have been adequate to preclude fouling; therefore, the effectiveness of lube oil chemistry control should be verified to ensure that fouling does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to verify the effectiveness of lube oil chemistry control for which a one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the UFSAR to verify that there are no steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil in the ESF systems at Salem. Instead, the applicant stated that titanium lube oil coolers are exposed to lubricating oil and are components in an ESF system (i.e., safety injection system).

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.2.1-6, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (a) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (b) the applicant stated that the One-Time Inspection Program will be used to examine titanium pump lube oil coolers to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.2.2.2.3.4 and, therefore, the applicant's AMR is consistent with the one under GALL Report items V.A-17, V.D1-12, V.A-12, V.D1-8, V.A-14, and V.D1-10.

Based on information in the UFSAR, the staff confirmed that the applicant's plant does not have steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil in the ESF systems. Therefore, the staff finds that this item is not applicable. Instead, titanium lube oil coolers are exposed to lubricating oil and are components in an ESF system (i.e., safety injection system). The staff reviewed this AMR and concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.4, item 1 criteria. For the line items that apply to LRA Section 3.2.2.2.4.1, 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).

(2) LRA Section 3.2.2.2.4, item 2 is referenced by LRA Table 3.2.1, item 3.2.1-10 and addresses stainless steel heat exchanger tubes exposed to a treated water environment, which are being managed for reduction of heat transfer due to fouling by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program in the residual heat removal heat exchangers.

The staff reviewed LRA Section 3.2.2.2.4, item 2 against the criteria in SRP-LR Section 3.2.2.2.4, item 2, which state that reduction of heat transfer due to fouling could occur for stainless steel heat exchanger tubes exposed to treated water. The SRP-LR also states that the existing program relies on control of water chemistry to manage reduction of heat transfer due to fouling and that a one-time inspection is an acceptable method to verify the effectiveness of the water chemistry controls.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of components associated with item 3.2.1-10, the staff finds the applicant's proposal to manage aging using the above programs acceptable because the Water Chemistry Program provides for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of heat transfer due to fouling. In addition, the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by determining sample sizes based on materials, environments, aging mechanisms, and operating experience and by identifying inspection locations and examination techniques, including acceptance criteria, based on the aging effects for which the components are being examined.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.4, item 2 criteria. For those line items that apply to LRA Section 3.2.2.2.4, item 2, 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).

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

LRA Section 3.2.2.2.5 addresses hardening and loss of strength due to elastomer degradation, stating that this aging effect is not applicable to the Salem units, which are PWRs. SRP-LR Section 3.2.2.2.5 states that hardening and loss of strength due to elastomer degradation may occur in elastomer seals and components of the BWR standby gas treatment system ductwork and filters exposed to uncontrolled indoor air. This item is not applicable to the Salem units because they are PWRs. On this basis, the staff finds that SRP-LR Section 3.2.2.2.5 criteria do not apply to Salem.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.5 criteria do not apply.

3.2.2.2.6 Loss of Material Due to Erosion

LRA Section 3.2.2.2.6 refers to LRA Table 3.2.1, item 3.2.1-12 and addresses stainless steel orifices exposed to treated borated water, which are being managed for loss of material due to erosion by the Water Chemistry Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the Water Chemistry Program to manage this aging effect for the charging pump minimum-flow orifice in the chemical and volume control system. The applicant also stated that the high-pressure charging pumps are not used for normal charging flow, unless the positive displacement pump is out of service for maintenance, and added that the positive displacement pump does not have flow through the recirculation orifice. The applicant concluded that an additional inspection of the minimum-flow recirculation orifice is not warranted.

The staff reviewed LRA Section 3.2.2.2.6 against the criteria in SRP-LR Section 3.2.2.2.6, which state that loss of material due to erosion could occur in the stainless steel HPSI pump minimum-flow recirculation orifice exposed to treated borated water. The SRP-LR also states that the GALL Report recommends a plant-specific AMP be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging and that acceptance criteria are described in Branch Technical Position RSLB-1.

In its review of components associated with item 3.2.1-12, the staff noted that the use of the Water Chemistry Program alone would not adequately manage this aging effect if the positive displacement pumps were out of service for extended periods of time. It was not clear to the staff how extensively the high-pressure charging pumps in the chemical and volume control system have been used for normal charging, which could cause erosion of the minimum-flow orifice.

During a conference call on July 22, 2010, the staff requested that the applicant provide additional information regarding the use of the associated pumps for normal charging. In its response to the RAI, dated August 26, 2010, the applicant provided a supplement to its LRA, stating that it had incorrectly included the aging mechanism of loss of material due to erosion for the restricting orifices in the safety injections and chemical and volume control systems. The applicant revised LRA Section 3.2.2.2.6 to state that LRA Table 3.2.1, item 3.2.1-12 did not apply to Salem and reiterated that an inspection of the orifices is not warranted to manage erosion on these restricting orifices because they only experience limited flow every quarter, during surveillance tests. The staff finds the applicant's revision to LRA Section 3.2.2.2.6 in the LRA supplement acceptable because the limited usage of the restricting orifices will not subject them to the aging effect described in Licensee Event Report (LER) 50-275/94-023, as referenced in the GALL Report for this item.

3.2.2.2.7 Loss of Material Due to General Corrosion and Fouling

The staff reviewed LRA Section 3.2.2.2.7 against the criteria in SRP-LR Section 3.2.2.2.7.

LRA Section 3.2.2.2.7 addresses loss of material due to general corrosion and fouling and states that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.2.2.2.7 states that loss of material due to general corrosion and fouling may occur on steel drywell and the suppression chamber spray system nozzle and flow orifice internal surfaces exposed to uncontrolled indoor air and may cause plugging of the spray nozzles and flow orifices.

This item applies to BWR steel drywell and the suppression chamber spray system and is, therefore, not applicable to the Salem units because they are PWRs. On this basis, the staff finds that SRP-LR Section 3.2.2.2.7 criteria do not apply to Salem.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.7 criteria do not apply.

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

The staff reviewed LRA Section 3.2.2.2.8 against the criteria in SRP-LR Section 3.2.2.2.8.

(1) LRA Section 3.2.2.2.8 addresses loss of material due to general, pitting, and crevice corrosion and states that this aging effect is not applicable to the Salem units, which are PWRs.

    SRP-LR Section 3.2.2.2.8 states that loss of material due to general, pitting, and crevice corrosion may occur in BWR steel piping, piping components, and piping elements exposed to treated water.

    This line item is not applicable to the Salem units because they are PWRs. On this basis, the staff finds that the SRP-LR criteria do not apply.

(2) LRA Section 3.2.2.2.8, item 2, associated with LRA Table 3.2.1, item 3.2.1-15, addresses loss of material due to general, pitting, and crevice corrosion for the internal surfaces of steel containment isolation piping, piping components, and piping elements exposed to treated water. The applicant stated that this line item is not applicable because there are no steel containment isolation piping, piping components, and piping elements exposed to treated water in the ESF systems. The staff reviewed LRA

Sections 2.3.2 and 3.2 and the UFSAR and confirmed that no in-scope internal surfaces of steel containment isolation piping, piping components, and piping elements exposed to treated water are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

(3) LRA Section 3.2.2.2.8, item 3, associated with LRA Table 3.2.1, item 3.2.1-16, addresses loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to lubricating oil. The applicant stated that this line item is not applicable because there is no steel piping, piping components, and piping elements exposed to lubricating oil in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and confirmed that no in-scope steel piping, piping components, and piping elements exposed to lubricating oil are present in the ESF systems and, therefore, finds the applicant's determination acceptable.

3.2.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Section 3.2.2.2.9 refers to Table 3.2.1, item 3.2.1-17 and addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping, piping components, and piping elements, with or without coating or wrapping, buried in soil. The applicant stated that this item is not applicable because there are no steel piping, piping components, and piping elements buried in soil in the ESF systems. The staff reviewed the LRA AMR items and information in the UFSAR associated with Table 3.2.1, item 3.2.1-17 and confirmed that there are no steel piping, piping components, and piping elements exposed to soil in the ESF systems. Therefore, the staff finds the applicant's determination that LRA Table 3.2.1, item 3.2.1-17 is not applicable acceptable.

3.2.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.2.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-3, the staff reviewed additional details of 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 3.2.2-3, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line 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 line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line 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 had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.2.2.3.1 Engineered Safety Features – Containment Spray System – Summary of Aging Management Evaluation – LRA Table 3.2.2-1

The staff reviewed LRA Table 3.2.2-1, which summarizes the results of AMR evaluations for the containment spray system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.2.2.1.

3.2.2.3.2 Engineered Safety Features – Residual Heat Removal System – Summary of Aging Management Evaluation – LRA Table 3.2.2-2

The staff reviewed LRA Table 3 2.2-2, which summarizes the results of AMR evaluations for the residual heat removal system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.2.2.1.

3.2.2.3.3 Engineered Safety Features – Safety Injection System – Summary of Aging Management Evaluation – LRA Table 3.2.2-3

The staff reviewed LRA Table 3.2.2-3, which summarizes the results of AMR evaluations for the safety injection system component groups.

In LRA Table 3.2.2-3, the applicant stated that stainless steel tanks exposed to soil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Aboveground Non-Steel Tanks Program. The AMR item cites generic note G, indicating that the environment is not evaluated in the GALL Report for this material and component combination.

The staff reviewed all AMR result line items in the GALL Report where the material is stainless steel and the aging effect/mechanism is loss of material due to pitting, crevice, and microbiologically-influenced corrosion and confirmed that for this environment, there are no entries in the GALL Report for this component and material.

The staff's evaluation of the applicant's Aboveground Non-Steel Tanks Program is documented in SER Section 3.0.3.3.3. The staff finds the applicant's proposal to manage aging using the Aboveground Non-Steel Tanks Program acceptable because it requires periodic visual inspections of the accessible tank outer surface and wall-thickness measurements of the inaccessible tank bottom external surface by UT, and the acceptance criteria is based on industry codes and the original design parameters of the tanks.

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 be maintained 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 the:

- auxiliary building ventilation system
- chemical and volume control system
- chilled water system
- circulating water system
- component cooling system
- compressed air system
- containment ventilation system
- control area ventilation system
- cranes and hoists
- demineralized water system
- emergency diesel generators and auxiliaries system
- fire protection system
- fresh water system
- fuel handling and fuel storage system
- fuel handling ventilation system
- fuel oil system
- heating water and heating steam system
- non-radioactive drain system
- radiation monitoring system
- radioactive drain system
- radwaste system
- sampling system
- service water system
- service water ventilation system
- spent fuel cooling system
- switchgear and penetration area ventilation system

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," 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 auxiliary systems components within the scope of license renewal and subject to an AMR 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 conducted an onsite audit of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified 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 had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Section 3.3.2.1 and 3.3.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.3.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.3-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary Systems Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	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	TLAA to be evaluated for structural girders of cranes. See SRP-LR Section 4.7 for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.3.2.2.1)
Steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water, or treated water (3.3.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.3.2.2.1)
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-3)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.2)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution > 60 °C (140 °F) (3.3.1-4)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.3(1))
Stainless steel and stainless clad steel heat exchanger components exposed to treated water > 60 °C (140 °F) (3.3.1-5)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.3(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-6)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.3(3))
Stainless steel non-regenerative heat exchanger components exposed to treated borated water > 60 °C (140 °F) (3.3.1-7)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water and ECT of tubes.	Yes	Water Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.2.4(1))
Stainless steel regenerative heat exchanger components exposed to treated borated water > 60 °C (140 °F) (3.3.1-8)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant-specific AMP is to be evaluated.	Yes	Water Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.2.4(2))
Stainless steel high-pressure pump casing in PWR chemical and volume control system (3.3.1-9)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant-specific AMP is to be evaluated.	Yes	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.4(3))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength steel closure bolting exposed to air with steam or water leakage. (3.3.1-10)	Cracking due to SCC and cyclic loading	Bolting Integrity. The AMP is to be augmented by appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.4(4))
Elastomer seals and components exposed to air-indoor uncontrolled (internal/external) (3.3.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.5(1))
Elastomer lining exposed to treated water or treated borated water (3.3.1-12)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.5(2))
Boral, boron steel spent fuel storage racks neutron-absorbing sheets exposed to treated water or treated borated water (3.3.1-13)	Reduction of neutron-absorbing capacity and loss of material due to general corrosion	A plant-specific AMP is to be evaluated.	Yes	Boral Monitoring and Water Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.2.6)
Steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-14)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.3.2.2.7(1))
Steel RCP oil collection system piping, tubing, and valve bodies exposed to lubricating oil (3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.3.2.2.7(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel RCP oil collection system tank exposed to lubricating oil (3.3.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection to evaluate the thickness of the lower portion of the tank	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.3.2.2.7(1))
Steel piping, piping components, and piping elements exposed to treated water (3.3.1-17)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.7(2))
Stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-18)	Loss of material/general (steel only), pitting, and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.7(3))
Steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil (3.3.1-19)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Buried Piping Inspection; Aboveground Steel Tanks; Buried Non-Steel Piping Inspection; RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants; and Structures Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.2.8)
Steel piping, piping components, piping elements, and tanks exposed to fuel oil (3.3.1-20)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion and fouling	Fuel Oil Chemistry and One-Time Inspection	Yes	One-Time Inspection and Fuel Oil Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.2.9(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components exposed to lubricating oil (3.3.1-21)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.9(2))
Steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water and treated borated water (3.3.1-22)	Loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation)	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.10(1))
Stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water (3.3.1-23)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.10(2))
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-24)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.10(2))
Copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external) (3.3.1-25)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.10(3))
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.3.1-26)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.3.2.2.10(4))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel HVAC ducting and aluminum HVAC piping, piping components, and piping elements exposed to condensation (3.3.1-27)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.10(5))
Copper alloy fire protection piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-28)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection, Compressed Air Monitoring, Fire Protection, and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.2.10(6))
Stainless steel piping, piping components, and piping elements exposed to soil (3.3.1-29)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.10(7))
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution (3.3.1-30)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.10(8))
Copper alloy piping, piping components, and piping elements exposed to treated water (3.3.1-31)	Loss of material due to pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.11)
Stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil (3.3.1-32)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Fuel Oil Chemistry and One-Time Inspection	Yes	One-Time Inspection and Fuel Oil Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.2.12(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-33)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.3.2.2.12(2))
Elastomer seals and components exposed to air-indoor uncontrolled (internal or external) (3.3.1-34)	Loss of material due to wear	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.3.2.2.13)
Steel with stainless steel cladding pump casing exposed to treated borated water (3.3.1-35)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, “Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks.”	Yes	One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.14)
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water (3.3.1-36)	Reduction of neutron-absorbing capacity due to Boraflex degradation	Boraflex Monitoring	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1-37)	Cracking due to SCC and IGSCC	BWR Reactor Water Cleanup System	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1-38)	Cracking due to SCC	BWR SCC and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel BWR spent fuel storage racks exposed to treated water > 60 °C (140 °F) (3.3.1-39)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Steel tanks in diesel fuel oil system exposed to air-outdoor (external) (3.3.1-40)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Aboveground Steel Tanks	Consistent with the GALL Report
High-strength steel closure bolting exposed to air with steam or water leakage (3.3.1-41)	Cracking due to cyclic loading and SCC	Bolting Integrity	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Steel closure bolting exposed to air with steam or water leakage (3.3.1-42)	Loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Steel bolting and closure bolting exposed to air-indoor uncontrolled (external) or air-outdoor (external) (3.3.1-43)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity, External Surfaces Monitoring, and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.3.2.1.3)
Steel compressed air system closure bolting exposed to condensation (3.3.1-44)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel closure bolting exposed to air-indoor uncontrolled (external) (3.3.1-45)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity; Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems; Structures Monitoring; and ASME Section XI, Subsection IWF	Consistent with the GALL Report (see SER Section 3.3.2.1.4)
Stainless steel and stainless steel clad piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water > 60 °C (140 °F) (3.3.1-46)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed-cycle cooling water (3.3.1-47)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed-cycle cooling water (3.3.1-48)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1-49)	Loss of material due to MIC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-50)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.3.1-51)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.3.1-52)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-53)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation (3.3.1-54)	Loss of material due to pitting and crevice corrosion	Compressed Air Monitoring	No	Compressed Air Monitoring, Periodic Inspection, and Fire Protection	Consistent with the GALL Report (see SER Section 3.3.2.1.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel ducting closure bolting exposed to air-indoor uncontrolled (external) (3.3.1-55)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with the GALL Report
Steel HVAC ducting and components external surfaces exposed to air-indoor uncontrolled (external) (3.3.1-56)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with the GALL Report
Steel piping and components external surfaces exposed to air-indoor uncontrolled (external) (3.3.1-57)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, Fire Protection, and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.7)
Steel external surfaces exposed to air-indoor uncontrolled (external), air-outdoor (external), and condensation (external) (3.3.1-58)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, Fire Protection, Fire Water System, and Structures Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.7)
Steel heat exchanger components exposed to air-indoor uncontrolled (external) or air-outdoor (external) (3.3.1-59)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, Fire Protection, and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.8)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to air-outdoor (external) (3.3.1-60)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling Handling) Systems, Fire Protection, and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.8)
Elastomer fire barrier penetration seals exposed to air-outdoor or air-indoor uncontrolled (3.3.1-61)	Increased hardness, shrinkage, and loss of strength due to weathering	Fire Protection	No	Fire Protection; Structures Monitoring; and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report (see SER Section 3.5.2.1-4)
Aluminum piping, piping components, and piping elements exposed to raw water (3.3.1-62)	Loss of material due to pitting and crevice corrosion	Fire Protection	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Steel fire rated doors exposed to air-outdoor or air-indoor uncontrolled (3.3.1-63)	Loss of material due to wear	Fire Protection	No	Fire Protection	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1-64)	Loss of material due to general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Reinforced concrete structural fire barriers – walls, ceilings, and floors exposed to air-indoor uncontrolled (3.3.1-65)	Concrete cracking and spalling due to aggressive chemical attack and reaction with aggregates	Fire Protection and Structures Monitoring	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete structural fire barriers – walls, ceilings, and floors exposed to air-outdoor (3.3.1-66)	Concrete cracking and spalling due to freeze thaw, aggressive chemical attack, and reaction with aggregates	Fire Protection and 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 or air-indoor uncontrolled (3.3.1-67)	Loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to raw water (3.3.1-68)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion and fouling	Fire Water System	No	Fire Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Sections 3.3.2.1.9 and 3.3.2.1-12)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-69)	Loss of material due to pitting and crevice corrosion and fouling	Fire Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-70)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion and fouling	Fire Water System	No	Fire Water System and Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.1.9)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to moist air or condensation (internal) (3.3.1-71)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Compressed Air Monitoring, Fire Protection, and Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1-10)
Steel HVAC ducting and components internal surfaces exposed to condensation (internal) (3.3.1-72)	Loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbiologically -influenced corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and Fire Protection	Consistent with the GALL Report (see SER Section 3.3.2.1.11)
Steel crane structural girders in load handling system exposed to air-indoor uncontrolled (external) (3.3.1-73)	Loss of material due to general corrosion	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) (3.3.1-74)	Loss of material due to wear	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
Elastomer seals and components exposed to raw water (3.3.1-75)	Hardening and loss of strength due to elastomer degradation; loss of material due to erosion	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System and RG 1.1.27, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report (see SER Section 3.5.2.1.4)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements (without lining/ coating or with degraded lining/coating) exposed to raw water (3.3.1-76)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Steel heat exchanger components exposed to raw water (3.3.1-77)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System, Fire Water System, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
Stainless steel, nickel-alloy, and copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-78)	Loss of material due to pitting and crevice corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-79)	Loss of material due to pitting and crevice corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-80)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Open-Cycle Cooling Water System	No	Periodic Inspection; Structures Monitoring; and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report (see SER Sections 3.3.2.1.13 and 3.5.2.1.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, and piping elements, exposed to raw water (3.3.1-81)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System and Periodic Inspection	Consistent with the GALL Report (see SER Section 3.3.2.1-14)
Copper alloy heat exchanger components exposed to raw water (3.3.1-82)	Loss of material due to pitting, crevice, galvanic, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Stainless steel and copper alloy heat exchanger tubes exposed to raw water (3.3.1-83)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to raw water, treated water, or closed-cycle cooling water (3.3.1-84)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching of Materials	Consistent with the GALL Report
Gray cast iron piping, piping components, and piping elements exposed to soil, raw water, treated water, or closed-cycle cooling water (3.3.1-85)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching of Materials	Consistent with the GALL Report
Structural steel (new fuel storage rack assembly) exposed to air-indoor uncontrolled (external) (3.3.1-86)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated borated water (3.3.1-87)	Reduction of neutron-absorbing capacity due to Boraflex degradation	Boraflex Monitoring	No	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Aluminum and copper alloy > 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-88)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report)
Steel bolting and external surfaces exposed to air with borated water leakage (3.3.1-89)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report
Stainless steel and steel with stainless steel cladding piping, piping components, piping elements, tanks, and fuel storage racks exposed to treated borated water > 60 °C (140 °F) (3.3.1-90)	Cracking due to SCC	Water Chemistry	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.1.15)
Stainless steel and steel with stainless steel cladding piping, piping components, and piping elements exposed to treated borated water (3.3.1-91)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry, ASME Section XI, Subsection IWF, and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.1.16)
Galvanized steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (3.3.1-92)	None	None	NA	None	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass piping elements exposed to air, air-indoor uncontrolled (external), fuel oil, lubricating oil, raw water, treated water, and treated borated water (3.3.1-93)	None	None	NA	None	Consistent with the GALL Report
Stainless steel and nickel-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.3.1-94)	None	None	NA	None	Consistent with the GALL Report
Steel and aluminum piping, piping components, and piping elements exposed to air-indoor controlled (external) (3.3.1-95)	None	None	NA	Not applicable	Not applicable to Salem (see SER Section 3.3.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.3.1-96)	None	None	NA	None	Consistent with the GALL Report
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (3.3.1-97)	None	None	NA	None	Consistent with the GALL Report
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air (3.3.1-98)	None	None	NA	Compressed Air Monitoring	(see SER Section 3.3.2.1.17)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and copper alloy < 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-99)	None	None	NA	None	Consistent with the GALL Report

The staff's review of the auxiliary systems component groups followed several approaches. One approach, documented in SER Section 3.3.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.3.2.2, discusses the staff's review of AMR results for components 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, discusses the staff's review of AMR results for components 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 That Are 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 Non-Steel Tanks
- Aboveground Steel Tanks
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boral Monitoring Program
- Boric Acid Corrosion
- Buried Non-Steel Piping Inspection
- Buried Piping Inspection
- Closed-Cycle Cooling Water System
- Compressed Air Monitoring

- External Surfaces Monitoring
- Fire Protection
- Fire Water System
- Flow-Accelerated Corrosion
- Fuel Oil Chemistry
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Lubricating Oil Analysis
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Open-Cycle Cooling Water System
- Periodic Inspection
- Selective Leaching of Materials
- Structures Monitoring Program
- Water Chemistry

LRA Tables 3.3.2-1 through 3.3.2-26 summarize AMRs for the auxiliary systems components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line 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 line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

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

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

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

The staff notes that in LRA Tables 3.3.2-2, 3.3.2-3, 3.3.2-5, 3.3.2-6, 3.3.2-10, 3.3.2-11, 3.3.2-12, 3.3.2-16, 3.3.2-17, 3.3.2-21, 3.3.2-22, and 3.3.2-25, there are multiple tank line items exposed to material and environment combinations including carbon steel exposed to closed-cycle cooling water, treated water, raw water, lube oil, and fuel oil; stainless steel exposed to treated borated water and raw water; carbon or low-alloy steel with stainless steel cladding exposed to treated borated water; aluminum exposed to treated water; and gray cast iron exposed to raw water. The staff also notes that the LRA does not have a line item for the tank material exposed to an air or wetted gas internal environment as would occur when the tank is partially full. The staff further notes that with the exception of some line items in LRA Tables 3.3.2-2, 3.3.2-21, and 3.3.2-25 (see following discussion), in each instance the LRA line items manage the aging of the tank internal surfaces using a program that requires an internal inspection of the tank when appropriate (e.g., the Closed-Cycle Cooling Water Program requires a one-time inspection of stagnant flow areas and internals of selected chemical mixing tanks). These programs include the Closed-Cycle Cooling Water System, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Periodic Inspection, One-Time Inspection, and the Fire Water System programs. The staff finally notes that in appropriate cases, the LRA line items use a chemistry control program inclusive of the Water Chemistry, Fuel Oil Chemistry, Lubricating Oil Analysis, and Closed-Cycle Cooling Water System programs. The staff finds these existing line items acceptable because: (1) the chemistry control program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, and (2) the inspection-related programs will provide reasonable assurance that an aging effect is not affecting the components intended function. The staff notes that in the case of some of the tanks included in LRA Tables 3.3.2-2, 3.3.2-21, and 3.3.2-25, the LRA line items manage the aging of the tank internals using the Water Chemistry Program. The staff finds these existing line items acceptable because: (1) the Water Chemistry Program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, (2) use of only the Water Chemistry Program is consistent with GALL Report items V.D1-30, VII.E1-17, and VII.A3-8 and there are no other GALL Report line items in Sections V.D1, VII.E1, and VII.A3 related to tanks that require anything more than the Water Chemistry Program, and (3) the GALL Report recommends that there is no AERM or recommended AMP for stainless steel tanks exposed to uncontrolled indoor uncontrolled or condensation.

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).

LRA Tables 3.3.2-9 and 3.3.2-14 were revised as a result of the July 8, 2010, response to RAI B.2.1.9-01. The revision added AMR items in these tables to reference the applicant's Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff notes that the Bolting Integrity Program is supplemented by other AMPs including, but not limited to, the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection programs. These other AMPs supplement the Bolting Integrity Program by providing for the inspections required by the Bolting Integrity Program for pressure-retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action revised the LRA to add bolting component items in the tables mentioned above that are consistent with the GALL Report and have designated them as such with generic note B.

The staff did not repeat its review of the matters described in the GALL Report; however, it 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 is discussed below.

The staff reviewed the LRA to confirm that the applicant: (1) provided a brief description of the system, components, materials, and environments; (2) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (3) identified those aging effects for the auxiliary systems components that are subject to an AMR.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.3.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

3.3.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.3.1, items 36 through 39 discuss the applicant's determination on the GALL Report AMR line items that are applicable only to BWR-designed reactors. In the applicant's AMR discussions for items 36 through 39, no additional information is provided. The staff confirmed that AMR items 36 through 39, in Table 1 of the GALL Report, Volume 1, are only applicable to BWR-designed reactors and that Salem is a PWR. Based on this determination, the staff finds that AMR items 36 through 39, in Table 1 of the GALL Report, Volume 1, are not applicable to Salem.

LRA Table 3.3.1, item 3.3.1-41 addresses high-strength steel closure bolting exposed to air with steam or water leakage in the auxiliary systems. The GALL Report recommends use of GALL AMP XI.M18, "Bolting Integrity," to manage cracking due to cyclic loading or SCC for this component group. The applicant stated that this item is not applicable because there is no high-strength closure bolting in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does not have any AMR results for the auxiliary systems that include high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR and confirmed that no high-strength steel closure bolting exposed to air with steam or water leakage within scope is present in the auxiliary systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-42 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends the use of GALL 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 the AMR methodology for steel closure bolting exposed to air with steam or water leakage adds pitting and crevice corrosion to general corrosion and as a result, item 3.3.1-43 is credited for this component instead. The staff evaluated the applicant's claim and found it acceptable because the applicant: (1) identified the loss of material due to the general, pitting, and crevice corrosion aging effect, which is a more conservative approach than the loss of material due to the general corrosion aging effect for this component group and (2) has credited an alternate Table 1 line item (item 3.3.1-43) to manage this component group.

LRA Table 3.3.1, item 3.3.1-44 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends the use of GALL 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 there is no steel closure bolting exposed to air with steam or water leakage in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does not have any AMR results for the auxiliary systems that include steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR and confirmed that no steel closure bolting exposed to air with steam or water leakage within scope is present in the auxiliary systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-49 addresses loss of material due to MIC for stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because this aging effect is not predicted for the corresponding components based on plant-specific operating experience. The staff reviewed the operating experience portion of LRA Section B.2.1.12 for the Closed-Cycle Cooling Water System Program and noted that, although MIC had been identified in the diesel generator jacket water components exposed to closed-cycle cooling water, these components are titanium and thus are not susceptible to MIC. The staff finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-53 addresses steel compressed air system piping, piping components, and piping elements exposed to condensation (internal). The GALL Report recommends use of GALL AMP XI.M24, “Compressed Air Monitoring,” to manage loss of material due to general and pitting corrosion for this component group. The applicant stated that this item is not applicable because this component, material, and environment combination is addressed by item 3.3.1-71 since item 3.3.1-53 does not include crevice corrosion, which is predicted for Salem for this component, material, and environment combination. The staff evaluated the applicant’s claim and found it acceptable because the applicant: (1) identified the loss of material due to the general, pitting, and crevice corrosion aging effect, which is a more conservative approach than the loss of material due to general and pitting corrosion aging effect for this component group and (2) has credited an alternate Table 1 line item (item 3.3.1-71) to manage this component group.

LRA Table 3.3.1, item 3.3.1-62 addresses aluminum piping, piping components, and piping elements exposed to raw water. The GALL Report recommends the use of GALL AMP XI.M26, “Fire Protection,” to manage loss of material due to pitting and crevice corrosion for this component group. The applicant stated that this line item is not applicable because the applicant does not have any aluminum piping, piping components, or piping elements exposed to raw water in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and noted that the applicant’s LRA does have AMR results for aluminum piping, piping components, and piping elements exposed to raw water in the auxiliary systems, but that these components are evaluated using alternative line items because they are exposed to open-cycle cooling water, and not fire water, so the Fire Protection Program would not be applicable. The staff also notes that item 3.3.1-62 is only applicable for components in the fire protection system. The staff reviewed the applicant’s UFSAR and confirmed that no aluminum piping, piping components, and piping elements exposed to raw water within scope are present in the fire protection systems and, therefore, finds the applicant’s determination acceptable.

LRA Table 3.3.1, item 3.3.1-64 addresses steel piping, piping components, and piping elements exposed to fuel oil. The GALL Report recommends the use of GALL AMPs XI.M30, “Fuel Oil Chemistry,” and XI.M26, “Fire Protection,” to manage loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this line item is not applicable because steel components exposed to fuel oil were aligned to item 3.3.1-20, which includes loss of material due to MIC and fouling, which are applicable aging effects. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant’s LRA does have AMR results for steel piping, piping components, and piping elements exposed to fuel oil in the auxiliary systems and that these items are being managed using item 3.3.1-20. The staff finds the applicant’s determination acceptable because the components are being managed for aging in accordance with an appropriate alternative line item.

LRA Table 3.3.1, item 3.3.1-65 addresses reinforced structural fire barriers (i.e., walls, ceiling, and floors) exposed to uncontrolled indoor air. The GALL Report recommends the use of GALL AMPs XI.M26, “Fire Protection,” and XI.S6, “Structures Monitoring Program,” to manage concrete cracking and spalling due to aggressive chemical attack and reaction with aggregates for this component group. The applicant stated that this line item is not applicable because the applicant addressed these aging effects and environments in LRA Section 3.5 for the appropriate buildings. The staff reviewed LRA Sections 3.3 and 3.5 and confirmed that structural fire barrier walls, ceilings, and floors exposed to indoor air are being managed for cracking and spalling by alternative line items from LRA Section 3.5. The staff finds the applicant’s determination acceptable because the components are being managed for aging in accordance with an appropriate alternative line item.

LRA Table 3.3.1, item 3.3.1-69 addresses stainless steel piping, piping components, and piping elements exposed to raw water. The GALL Report recommends the use of GALL AMP XI.M27 "Fire Water System," to manage loss of material due to pitting and crevice corrosion and fouling for this component group. The applicant stated that this line item is not applicable because stainless steel components exposed to raw water were aligned to item 3.4.1-33, which includes loss of material due to MIC, which is an applicable aging effect. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does have AMR results for stainless steel piping, piping components, and piping elements exposed to raw water in the auxiliary systems and that these items are being managed using item 3.4.1-33. The staff finds the applicant's determination acceptable because the components are being managed for aging in accordance with an appropriate alternative line item.

LRA Table 3.3.1, item 3.3.1-78 addresses loss of material due to pitting and crevice corrosion for stainless steel, nickel-alloy, and copper alloy piping, piping components, and piping elements exposed to raw water. The applicant stated that this item is not applicable because the corresponding components exposed to raw water require consideration of MIC, which are evaluated in item 3.3.1-80. The staff noted that item 3.3.1-80 included all the aging mechanisms in item 3.3.1-78 plus MIC. The staff reviewed LRA Sections 2.3.3 and 3.3 and noted that the corresponding components had been evaluated using item 3.3.1-80 and, therefore, finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-79 addresses loss of material due to pitting and crevice corrosion and fouling for stainless steel piping, piping components, and piping elements exposed to raw water. The applicant stated that this item is not applicable because the component, material, environment, and aging effect combination do not apply to stainless steel materials in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does not have any AMR results for this material environment and aging effect combination and, therefore, finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-86 addresses the structural steel new fuel storage rack assembly exposed externally to uncontrolled indoor air. The GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," to manage loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this line item is not applicable because its AMR methodology for the steel new fuel storage rack assembly does not predict loss of material due to pitting and crevice corrosion and, therefore, this item was realigned to item 3.3.1-58. The staff notes that item 3.3.1-58 addresses steel external surfaces exposed to indoor uncontrolled air and credits the Structures Monitoring Program to manage loss of material due to general corrosion for this component group. The staff evaluated the applicant's claim and found it acceptable because: (1) the applicant has aligned the component to an appropriate alternative line item which credits the same program to manage loss of material as item 3.3.1-86; (2) the applicant's Structures Monitoring Program will be consistent, after enhancement, with GALL AMP XI.S6, which manages loss of material for structural steel components; and (3) during the AMP audit, the staff independently determined that plant operating experience had been adequately incorporated into the applicant's program and this operating experience review revealed no degradation not bounded by industry experience.

LRA Table 3.3.1, item 3.3.1-87 addresses reduction of neutron-absorbing capacity due to Boraflex degradation in Boraflex spent fuel storage rack neutron-absorbing sheets exposed to treated borated water. The applicant stated that this line item is not applicable because there are no Boraflex spent fuel storage rack neutron-absorbing sheets exposed to treated borated water for the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does not have any AMR results that include Boraflex spent fuel storage rack neutron-absorbing sheets exposed to treated borated water. The staff also reviewed the applicant's UFSAR and confirmed that no Boraflex spent fuel storage rack neutron-absorbing sheets exposed to treated borated water within scope are present in the spent fuel storage system and, therefore, finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-95 addresses steel and aluminum piping, piping components, and piping elements externally exposed to indoor controlled air. The applicant stated that this line item is not applicable because all indoor air was assumed to be uncontrolled for the purposes of license renewal. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does have AMR results for steel and aluminum piping, piping components, and piping elements externally exposed to indoor uncontrolled air and that those items are being managed by alternative line items applicable to indoor uncontrolled air. The staff finds the applicant's determination acceptable because uncontrolled air is a more aggressive environment than controlled air and the items are being managed by appropriate alternative line items.

3.3.2.1.2 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-27 addresses stainless steel HVAC ducting and aluminum HVAC piping, piping components, and piping elements exposed to condensation for loss of material due to pitting and crevice corrosion. The LRA credits the Periodic Inspection Program to manage the aging effect for stainless steel piping and fittings and valve bodies in Table 3.3.2-7. The GALL Report recommends a plant-specific AMP to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

In its review of the LRA of components associated with item 3.3.1-27 for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage the aging effects in stainless steel and aluminum piping and its components and elements with visual and volumetric inspections for loss of material.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. In its review of components associated with item 3.3.1-27, the staff finds the applicant's proposal to manage aging effects using the Periodic Inspection Program acceptable because it includes: (1) periodic visual inspections of piping and fittings and valve bodies and (2) ultrasonic wall thickness measurements of piping systems, which are adequate to detect loss of material, thinning, and fouling.

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).

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

LRA Table 3.3.1, item 3.3.1-43 addresses steel bolting and closure bolting exposed externally to indoor air or outdoor air, which is being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M18 recommends using visual inspections to manage the aging of these line items. In its review of components associated with item 3.3.1-43 for which the applicant cited generic note E, the staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon and low-alloy steel bolting through the use of visual inspections.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.4. In its review of components associated with item 3.3.1-43, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because: (1) its visual inspections are effective methods for detecting the applicable aging effects, (2) the frequency of monitoring is adequate to prevent significant degradation, and (3) the methods are consistent with the GALL Report recommended AMP.

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).

3.3.2.1.4 Loss of Preload Due to Self-Loosening

LRA Table 3.3.1, item 3.3.1-45 addresses steel closure bolting exposed externally to indoor air, which is being managed for loss of preload due to self-loosening. The LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M18 recommends using visual inspections and industry guidance on proper selection of bolting materials, lubricants, and torque to manage the aging of these line items. In its review of components associated with item 3.3.1-45 for which the applicant cited generic note E, the staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon and low-alloy steel bolting through the use of visual inspections and industry guidance on bolting materials, lubricants, and torque.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.4. In its review of components associated with item 3.3.1-45, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because: (1) its visual inspections are effective methods for detecting the applicable aging effects; (2) incorporation of industry guidance on proper selection of bolting materials, lubricants, and torque are effective methods for preventing loss of preload; (3) the frequency of monitoring is adequate to prevent significant degradation; and (4) the inspection methods are consistent with the GALL Report recommended AMP.

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).

3.3.2.1.5 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1-50 addresses galvanized steel, aluminum, stainless steel support members, welds, bolted connections, support anchorage to building structures exposed to outdoor air which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Periodic Inspection Program to manage the aging effect for aluminum louvers, flame arrestor, bird screen, and insulation jacketing (wire mesh, straps, and clips) and stainless steel piping and fittings, restricting orifices, valve bodies, bird screens, thermowells, insulation jacketing (wire mesh, straps, and clips), and bolting in Tables 3.2.2-3, 3.3.2-1, 3.3.2-2, 3.3.2-8, 3.3.2-16, 3.3.2-19, 3.3.2-23, 3.3.2-24, 3.4.2-4, and 3.5.2-9. The GALL Report recommends GALL AMP XI.S6, “Structures Monitoring Program,” to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.S6 is a plant-specific program that follows 10 CFR 50.65, “The Maintenance Rule”; RG 1.160, Revision 2, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants”; and references ANSI/American Society of Civil Engineers (ASCE) 11-90, “Guideline for Structural Condition Assessment of Existing Buildings.” These codes, industry standards, and guidelines recommend periodic visual inspections, NDE tests, and destructive tests (field and laboratory) supplemented by additional testing or analysis as required for proper evaluation of aging effects. In its review of the LRA of components associated with item 3.5.1-50 for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage the aging effects of aluminum and stainless steel piping and fittings, insulation, and other related components as listed above exposed to outdoor air, through periodic visual and volumetric inspection methods for loss of material due to pitting and crevice corrosion.

The staff’s evaluation of the applicant’s Periodic Inspection Program is documented in SER Section 3.0.3.3.2. In addition, the staff reviewed NUREG-1833, “Technical Bases for Revision to the License Renewal Guidance Documents,” and notes that stainless steel and aluminum in an outdoor air environment could result in loss of material. This review also notes that although the Structures Monitoring Program manages this aging effect by performing routine visual inspections of the structural materials’ surfaces, a similar program based on the same inspection techniques could also be credited, providing a reasonable assurance that the components’ intended functions will be maintained within the CLB for the period of extended operation. In its review of components associated with item 3.5.1-50, the staff finds the applicant’s proposal to manage aging effects using the Periodic Inspection Program acceptable because it includes periodic visual inspections of components and ultrasonic wall thickness measurements of piping and its components that are appropriate to detect loss of material.

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).

3.3.2.1.6 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-54 addresses stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation, which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Fire Protection Program to manage loss of material for stainless steel spray nozzles, piping and fittings, and valve bodies exposed to wetted air or gas in the fire protection system. The GALL Report recommends GALL AMP XI.M24, "Compressed Air Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The LRA also cites plant-specific note 2, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M24 recommends control of contaminants in order to limit loss of material due to corrosion and leakage testing to detect loss of material. In its review of components associated with item 3.3.1-54 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage loss of material for stainless steel spray nozzles, piping and fittings, and valve bodies exposed internally to wetted air or gas in LRA Table 3.3.2-12.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.5. The staff notes that the Fire Protection Program manages aging for: (1) fire barriers by performing visual inspections, (2) the diesel-driven fire pump fuel supply lines through performance testing, and (3) the external surfaces of the halon and CO_2 systems through visual inspection. However, the description of the Fire Protection Program does not include criteria for inspections of the internal surfaces of components or leakage testing which could detect loss of material. It is not clear to the staff how the Fire Protection Program is adequate to manage loss of material for these stainless steel components exposed internally to wetted air or gas.

In RAI 3.3.2.12-02 dated June 25, 2010, the staff requested that the applicant justify how the Fire Protection Program will adequately manage loss of material due to pitting and crevice corrosion for the stainless steel components exposed to an internal environment of wetted air or gas.

In its response dated July 21, 2010, the applicant stated that the Fire Protection Program does not inspect the internal surfaces of components and was not the appropriate program to manage loss of material for components exposed to internal condensation, which are part of the fire water suppression systems. As a result, the applicant revised the AMR line items in LRA Table 3.3.2-12 for the stainless steel iodine removal filter spray nozzles, piping and fittings, and valve bodies that reference item 3.3.1-54 to credit the Fire Water System Program to manage loss of material. The staff finds the applicant's response to RAI 3.3.2.12-02 and its use of the Fire Water System Program to manage loss of material for these components exposed to internal condensation acceptable because: (1) the components are not part of the compressed air system so the preventive measures in the GALL Report recommended AMP would not be appropriate; and (2) the Fire Water System Program includes volumetric inspections, system performance testing, and flow tests which are capable of detecting loss of material in components exposed to internal condensation.

In addition, the applicant stated in its response to RAI 3.3.2.12-02 that the stainless steel spray nozzles in the halon and CO_2 systems are open such that the internal surfaces are exposed to the same environment as the external surfaces, which is indoor air. As a result, the applicant revised the AMR result lines in LRA Table 3.3.2-12 for the halon and CO_2 stainless steel spray nozzles to change the environment to indoor air and change the Table 1 item reference to item 3.3.1-94 with no AERMs or AMP, citing generic note A. The applicant also stated that additional AMR results were required in order to distinguish between those portions of the fire protection system which are subject to internal condensation (i.e., components in the fire water suppression systems) and those which are not (i.e., components in the halon and CO_2 suppression systems that are downstream of the isolation valves). As a result, the applicant also revised LRA Table 3.3.2-12 to add two new AMR result lines for stainless steel piping and fittings and valve bodies exposed internally to indoor air which reference item 3.3.1-94, have no AERMs and no AMP, and cite generic note A. The staff finds the applicant's response acceptable because: (1) the internal environment for components downstream from the isolation valves in the halon and CO_2 fire suppression systems should be the same as the external environment; (2) the external environment for the halon and CO_2 fire suppression systems is indoor air, which is not expected to contribute to corrosion of these components; (3) the applicant has chosen appropriate alternate line items that recommend no aging effects for these components when exposed to an indoor air environment; and (4) the applicant has made the corresponding revisions to the LRA. The staff's concern described in RAI 3.3.2.12-02 is resolved.

LRA Table 3.3.1, item 3.3.1-54 addresses stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation for loss of material due to pitting and crevice corrosion. The LRA credits the Periodic Inspection Program to manage the aging effect for stainless steel strainers, piping and fittings, valve bodies, pump casings, filter housing, flow element, thermowell, and heat exchanger components in Tables 3.3.2-6, 3.3.2-11, 3.3.2-14, 3.3.2-19, and 3.3.2-21. The GALL Report recommends GALL AMP XI.M24, "Compressed Air Monitoring," to ensure that these aging effects are adequately managed. The associated AMR line items cite generic note E.

For those line items associated with generic note E, GALL AMP XI.M24 recommends visual inspections, monitoring the level of contaminants, and leak rate testing of the entire system, especially of components made of carbon and stainless steels, for loss of material in the compressed air system. The AMP discusses preventive maintenance only in the context of the inoperability of air-operated components impacted by corrosion and other contaminants. In its review of the LRA of components associated with item 3.3.1-54 for which the applicant cited generic note E, the staff notes that the Periodic Inspection Program proposes to manage the aging effects of passive stainless steel piping system components and other elements as described above (e.g., strainers, pump casings, filter housing, flow element, thermowell, etc.) and heat exchanger components with visual and volumetric inspections for loss of material, thinning, and fouling that could result in reduction of heat transfer.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. In addition to that review, the staff also reviewed NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," and notes that although GALL AMP XI.M24 is recommended for this function, a similar program based on the same inspection techniques could also be credited providing the assurance that the components' intended functions will be maintained within the CLB for the period of extended operation. In its review of components associated with item 3.3.1-54, the staff finds the applicant's proposal to manage aging effects using the Periodic Inspection Program acceptable because it includes periodic visual inspections of components and ultrasonic wall thickness measurements of piping systems and heat exchanger components which are adequate to detect loss of material, thinning, and fouling.

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).

3.3.2.1.7 Loss of Material Due to General Corrosion

LRA Table 3.3.1, item 3.3.1-57 addresses steel piping and components external surfaces exposed to indoor uncontrolled air, which are being managed for loss of material due to general corrosion. LRA Table 3.3.1, item 3.3.1-58 addresses steel piping and components external surfaces exposed to indoor uncontrolled air, outdoor air, and condensation, which are being managed for loss of material due to general corrosion. The LRA credits the Fire Protection Program in addition to the External Surfaces Monitoring Program to manage aging for steel gas bottles, CO_2 tanks, piping and fittings, and steel and galvanized steel fire barrier doors in the fire protection system. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The AMR line items that credit the Fire Protection Program cite generic note E. The LRA also cites plant-specific note 10, which indicates that the Fire Protection Program will be used in addition to the External Surfaces Monitoring Program.

The staff reviewed the applicant’s Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.5. In its review of components associated with items 3.3.1-57 and 3.3.1-58, the staff notes that the Fire Protection Program proposes to manage loss of material for the external surfaces of these steel components through the use of periodic visual inspections. GALL AMP XI.M36 also recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. The staff finds the LRA proposed AMP acceptable because: (1) the proposed inspection methods are the same as the inspection methods in the GALL Report recommended AMP and (2) the applicant is using the Fire Protection Program in addition to the External Surfaces Monitoring Program, which provides a more comprehensive approach to managing this aging effect.

LRA Table 3.3.1, items 3.3.1-57 and 3.3.1-58 address steel piping and components external surfaces exposed to indoor uncontrolled air, outdoor air, and condensation, which are being managed for loss of material due to general corrosion. The LRA credits the Fire Water System Program in addition to the External Surfaces Monitoring Program for cast iron flow alarm switches, diesel-driven fire pump casing, strainer bodies, and valve bodies and carbon steel piping and fittings, jockey fire pump casing, and retarding chamber tanks exposed to indoor air in the fire protection system. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The AMR line items that credit the Fire Water System Program cite generic note E. The AMR line items also cite plant-specific note 8, which indicates that the Fire Water System Program will be used in addition to the External Surfaces Monitoring Program.

The staff reviewed the applicant’s Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.6. In its review of components associated with Table 3.3-1, items 3.3.1-57 and 3.3.1-58, the staff noted that the Fire Water System Program proposes to manage the aging effects of these items through the use of periodic visual inspections. GALL AMP XI.M36 also recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. The staff finds the LRA proposed AMP acceptable to manage aging for these components because: (1) the proposed inspection methods are the same as the methods in the GALL Report recommended AMP and (2) the applicant is using the

Fire Water System Program in addition to the External Surfaces Monitoring Program, which provides a more comprehensive approach to managing this aging effect.

LRA Table 3.3.1, item 3.3.1-58 addresses steel external surfaces that are being managed for loss of material due to general corrosion. The LRA credits the Structures Monitoring Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The associated AMR line item in LRA Table 3.3.2-14 cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M36 recommends using general visual inspections of external surfaces to manage the aging of these line items. In its review of components associated with item 3.3.1-58 for which the applicant cited generic note E and the Structures Monitoring Program, the staff noted that the Structures Monitoring Program proposes to manage the aging of steel surfaces of new fuel storage racks through the use of visual inspections.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. In its review of components associated with item 3.3.1-58, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the applicant's program uses visual inspections which are equivalent to the inspections recommended by GALL AMP XI.M36.

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).

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

LRA Table 3.3.1, items 3.3.1-59 and 3.3.1-60 address steel heat exchanger components, piping, piping components, and piping elements exposed to indoor uncontrolled air or outdoor air which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Water System Program in addition to the External Surfaces Monitoring Program to manage aging for steel piping and fittings, gray cast iron fire hydrants and hose manifolds, and ductile cast iron piping and fittings exposed to outdoor air or air with steam or water leakage in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The AMR line items that credit the Fire Water System Program cite generic note E. The AMR line items also cite plant-specific note 8, indicating that the Fire Water System Program will be used in addition to the External Surfaces Monitoring Program.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.6. In its review of components associated with Table 3.3-1, items 3.3.1-59 and 3.3.1-60, the staff notes that the Fire Water System Program proposes to manage the aging effects of these components through the use of periodic visual inspections. GALL AMP XI.M36 also recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. The staff finds the LRA proposed AMP acceptable to manage aging for these components because: (1) the proposed inspection methods are the same as the methods in the GALL Report recommended AMP and (2) the applicant is using the Fire Water System Program in addition to the External Surfaces

Monitoring Program, which provides a more comprehensive approach to managing this aging effect.

LRA Table 3.3.1, item 3.3.1-59 addresses steel heat exchanger components exposed to indoor uncontrolled air or outdoor air, which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Protection Program to manage aging for steel and galvanized steel fire barrier doors exposed to outdoor air in the fire protection system. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The LRA also cites plant-specific note 2, indicating that the Fire Protection Program will be substituted for the External Surfaces Monitoring Program.

The staff reviewed the applicant’s Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.5. In its review of components associated with item 3.3.1-59, the staff notes that the Fire Protection Program proposes to manage loss of material for the steel and galvanized steel fire barrier doors through the use of periodic visual inspections. GALL AMP XI.M36 also recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. The staff finds the LRA proposed AMP acceptable because the proposed inspection methods are the same as the methods in the GALL Report recommended AMP.

LRA Table 3.3.1, item 3.3.1-60 addresses steel piping, piping components, and piping elements exposed externally to outdoor air, which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Protection Program in addition to the External Surfaces Monitoring Program to manage aging for steel and galvanized steel piping and fittings exposed to outdoor air in the fire protection system. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The AMR line items that credit the Fire Protection Program cite generic note E. The LRA also cites plant-specific note 10, which indicates that the Fire Protection Program will be used in addition to the External Surfaces Monitoring Program.

The staff reviewed the applicant’s Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.5. In its review of components associated with item 3.3.1-60, the staff notes that the Fire Protection Program proposes to manage loss of material for the steel and galvanized steel piping and fittings external surfaces through the use of periodic visual inspections. GALL AMP XI.M36 also recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. The staff finds the LRA proposed AMP acceptable because: (1) the proposed inspection methods are the same as those in the GALL Report recommended AMP, and (2) the applicant is using the Fire Protection Program in addition to the External Surfaces Monitoring Program, which provides a more comprehensive approach to managing this aging effect.

LRA Table 3.3.1, item 3.3.1-60 addresses steel piping, piping components, and piping elements exposed externally to outdoor air, which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M36 recommends using visual inspections to manage the aging of these line items. In its review of components associated with item 3.3.1-60 for which the applicant cited generic note E, the staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon steel cranes and hoists through the use of visual inspections.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.4. In its review of components associated with item 3.3.1-60, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because: (1) its visual inspections are effective methods for detecting the applicable aging effects, (2) the frequency of monitoring is adequate to prevent significant degradation, and (3) the proposed inspection method is consistent with the method in the GALL Report recommended AMP.

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).

3.3.2.1.9 Loss of Material Due to General, Pitting, Crevice, Galvanic, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-68 addresses steel piping, piping components, and elements exposed to raw water, which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for carbon steel piping, fittings, and valve bodies and gray cast iron pump casings, tanks (HHB condensate receiver and level pot), and drain traps in Tables 3.3.2-5, 3.3.2-17, 3.3.2-18, and 3.3.2-21. The GALL Report recommends GALL AMP XI.M27, "Fire Water System," to ensure that these aging effects are adequately managed. The associated AMR line items cite generic note E.

For those line items associated with generic note E, GALL AMP XI.M27 recommends routine (or during corrective maintenance) visual inspections of piping internals as an alternate method to identify loss of material and wall thinning, verify the existence of unobstructed internal flow, and ensure their fitness against catastrophic failure. In its review of components associated with item 3.3.1-68, for which the applicant cited generic note E, the staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage loss of material through visual inspections during surveillances, maintenance activities, and outages. The applicant stated that when the inspections yield evidence of loss of material or fouling that could potentially impair these components' intended functions, it evaluates the components' degraded condition and, if warranted, implements its corrective action program.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.15. The staff notes that the performance of periodic visual inspections, further evaluation of potentially impaired components, and application of the corrective action program for degraded components provide similar detection and prevention methods as those recommended in GALL AMP XI.M27. In its review of components associated with item 3.3.1-68, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the visual inspection techniques used in the two programs to detect loss of material have no substantive differences.

LRA Table 3.3.1, item 3.3.1-68 addresses steel piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Fire Water System Program to manage loss of material for gray cast iron retarding chamber tanks exposed to raw water in Table 3.3.2-12. The AMR line items cite generic note C.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.6. The staff notes that the Fire Water System Program includes wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. It is not clear from a review of the applicant's Fire Water System Program whether volumetric inspections to detect loss of material due to corrosion will be performed on the internal surfaces (specifically the bottom) of the retarding chamber tanks. In RAI 3.3.2.12-01 dated June 17, 2010, the staff requested that the applicant clarify if these tanks are included in the sample of fire protection system components that will be volumetrically inspected for wall thickness to detect loss of material prior to loss of intended function.

In its response dated July 15, 2010, the applicant stated that it does not use retarding chamber tanks in the portion of the fire protection system that is within the scope of license renewal, but instead uses time delays. The applicant also stated that retarding chamber tanks are only used in the portions of the system that are not within the scope of license renewal and were inadvertently included in LRA Table 3.3.2-12. The applicant revised LRA Table 3.3.2-12 to delete the AMR results related to the retarding chamber tanks. The staff finds the applicant's response to RAI 3.3.2.12-01 acceptable because the retarding chamber tanks are not within the scope of license renewal and, therefore, do not require aging management.

LRA Table 3.3.1, item 3.3.1-70 addresses copper alloy piping, piping components, and piping elements exposed to raw water for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Periodic Inspection Program to manage the aging effect for copper-Zn alloyed valve bodies internally exposed to raw water in Table 3.3.2-18. The GALL Report recommends GALL AMP XI.M27, "Fire Water System," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M27 recommends routine (or during corrective maintenance) visual inspections of piping internals as an alternate method to identify loss of material and wall thinning, verify the existence of unobstructed internal flow, and ensure their fitness against catastrophic failure. In its review of components associated with item 3.3.1-70, for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage piping system loss of material through visual inspections, followed up with volumetric inspections at locations most susceptible to aging effects during maintenance activities based on industry and plant-specific operating experience. The applicant stated that when the inspections yield evidence of loss of material or fouling that could potentially impair these components' intended function, it evaluates the components' degraded condition and, if warranted, implements its corrective action program.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements of piping and its components to detect loss of material and fouling. The staff also notes that the components included in item 3.3.1-70 are made of copper with less than 15 percent Zn and, therefore, are resistant to SCC, selective leaching, and pitting and crevice corrosion. The staff further notes that although NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," recommends GALL AMP XI.M27 for this function, it also discusses that each time such systems are opened, the introduced oxygen could result in possible loss of material in components. In lieu of intrusive inspections, the staff recommends volumetric testing of the system, when possible. The applicant's Periodic Inspection Program provides for both visual and volumetric inspections of the piping system for the detection of loss of material and fouling, thus providing a reasonable assurance that the components' intended functions will be maintained within the CLB for the period of extended operation. In its review of components associated with item 3.3.1-70, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it includes periodic visual and volumetric inspections of the piping system and its components to detect loss of material, thinning, and fouling.

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).

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

LRA Table 3.3.1, item 3.3.1-71 addresses steel piping, piping components, and piping elements exposed internally to moist air or condensation which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Protection and Fire Water System programs to manage these aging effects for steel piping and fittings in the fire protection system. The GALL Report recommends GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The AMR line item that credits the Fire Protection Program also cites plant-specific note 2, which indicates that the Fire Protection program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination. The AMR line item that credits the Fire Water System Program also cites plant-specific note 9, which indicates that the Fire Water System Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

GALL AMP XI.M38 recommends inspections of the internal surfaces of piping and components to detect loss of material. In its review of components associated with Table 3.3-1, item 3.3.1-71 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage loss of material for steel piping and fittings exposed internally to wetted air or gas in LRA Table 3.3.2-12.

The staff reviewed the applicant's Fire Protection and Fire Water System programs and its evaluations are documented in SER Sections 3.0.3.2.5 and 3.0.3.2.6, respectively. The staff noted that the Fire Protection Program manages the aging effects for: (1) fire barriers by performing visual inspections, (2) the diesel-driven fire pumps fuel supply lines through performance testing, and (3) the external surfaces of halon and CO_2 systems through visual inspection. However, the staff also noted that the description of the Fire Protection Program does not include criteria for inspections of the internal surfaces of components or leakage testing which could detect loss of material, which is included in the GALL Report recommended AMP. It is not clear to the staff how the Fire Protection Program is adequate to manage loss of material for these components exposed internally to wetted air or gas. In RAI 3.3.2.12-02 dated June 25, 2010, the staff requested that the applicant justify how the Fire Protection Program will adequately manage loss of material due to pitting and crevice corrosion for the components exposed to an internal environment of wetted air or gas; and clarify if both the Fire Protection Program and Fire Water System Program will be used to manage loss of material for these components.

In its response dated July 21, 2010, the applicant stated that the CO_2 dispersion system contains carbon steel piping and fittings between the isolation valves and open spray nozzles that are exposed to the same environment as the external surfaces. The applicant also stated that the environment was conservatively listed as wetted air or gas, but that these components are not subject to internal condensation. As a result, the applicant revised the AMR line item that credited the Fire Protection Program to change the environment to indoor air and change the credited program to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, citing generic note A, which indicates that the line item is being managed consistent with the GALL Report recommendations. The staff finds the applicant's response to RAI 3.3.2.12-02 and its use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable to manage aging for these components exposed to indoor air because it includes visual inspections of the internal surfaces of components which are capable of detecting loss of material and is consistent with the GALL Report recommendations for managing aging for these components. The staff also finds the applicant's use of the Fire Water System Program acceptable to manage the components exposed to internal condensation because it includes volumetric inspections, system performance testing, and flow tests which are capable of detecting loss of material in components exposed to internal condensation.

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).

3.3.2.1.11 Loss of Material Due to General, Pitting, Crevice, and (For Drip Pans and Drain Lines) Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-72 addresses steel HVAC ducting and components internal surfaces exposed to internal condensation, which are being managed for loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbiologically-influenced corrosion. The LRA credits the Fire Protection Program for galvanized steel damper housings in the fire protection system. The GALL Report recommends GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program," to ensure that these aging effects are adequately managed. The AMR line item cites generic note E. The LRA also cites plant-specific note 2, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M38 recommends inspections of the internal surfaces of piping and components to detect loss of material. In its review of components associated with Table 3.3-1, item 3.3.1-72 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage loss of material for galvanized steel damper housings exposed internally to wetted air or gas.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.5. The staff notes that the Fire Protection Program manages the aging effects for: (1) fire barriers by performing visual inspection, (2) the diesel-driven fire pumps' fuel supply lines through performance testing, and (3) the external surfaces of the halon and CO_2 systems through visual inspection. However, the staff also notes that the description of the Fire Protection Program does not include criteria for inspections of the internal surfaces of components or leakage testing which could detect loss of material, which is included in the GALL Report recommended AMP. It is not clear to the staff how the Fire Protection Program is adequate to manage loss of material for these components exposed internally to wetted air or gas.

By letter dated June 25, 2010, the staff issued RAI 3.3.2.12-02 requesting that the applicant justify how the Fire Protection Program will adequately manage loss of material due to pitting and crevice corrosion for the components exposed to an internal environment of wetted air or gas.

In its response dated July 21, 2010, the applicant stated that the Fire Protection Program includes inspections of all fire dampers with fusible links at least once every 18 months, but that in order to ensure fire dampers that do not have fusible links are properly inspected, additional line items must be added to the LRA. The applicant revised LRA Table 3.3.2-12 to include two additional line items for galvanized steel damper housings exposed internally to wetted air or gas, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, reference item 3.3.1-72, and cite generic note A. The applicant also revised LRA Section B.2.1.15 to clarify that all fire dampers equipped with fusible links, which penetrate fire barriers, are to be visually inspected at least once per refueling cycle (18 months) and functionally tested, as required. The staff confirmed that the Fire Protection Program includes activities to inspect fire dampers with fusible links at least once every 18 months. The staff finds the applicant's response to RAI 3.3.2.12-02 and its use of the aforementioned programs to manage aging for fire dampers with and without fusible links exposed to internal condensation acceptable because each program includes visual inspections of fire dampers which are appropriate for detecting loss of material and are consistent with the inspection methods in the GALL Report recommended AMP.

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).

3.3.2.1.12 Loss of Material Due to General, Pitting, Crevice, Galvanic, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-77 addresses 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. The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for carbon steel piping and fittings in Table 3.3.2-17. The GALL Report recommends GALL AMP XI.M20, “Open-Cycle Cooling Water System,” to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For the line item associated with generic note E, GALL AMP XI.M20 visually monitors the condition of the open-cycle cooling water system components and their coated surfaces exposed to a water environment for loss of material. In addition, when necessary, the program performs nondestructive (e.g., UT, ECT) testing to measure wall thinning and preventive measures (e.g., chemical treatment, system flushing) to assure that aging effects due to MIC, biofouling, and silt are managed for safety-related components within the scope of GL 89-13. Inspections are performed annually or during refueling outages. In its review of components associated with item 3.3.1-77, for which the applicant cited generic note E, the staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage aging of the referenced carbon steel heat exchanger components through visual inspections during surveillances, maintenance activities, and outages. When the inspections yield evidence for loss of material or fouling that could potentially impair these components’ intended function, then the applicant stated it evaluates the degraded components and, if warranted, implements its corrective action program.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.15. The staff notes that the performance of periodic visual inspections, further evaluation of potentially impaired components, and application of the corrective action program for degraded components implemented by the Inspection of Surfaces in Miscellaneous Piping and Ducting Components Program provides similar detection as GALL AMP XI.M20. In its review of components associated with item 3.3.1-77, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because: (1) the components being managed by the program are nonsafety-related and not within the scope of GL 89-13, therefore, the preventive measures in GALL AMP XI.M20 are not appropriate; and (2) its visual inspections are as comprehensive as the GALL AMP XI.M20 inspections for this nonsafety-related item.

LRA Table 3.3.1, item 3.3.1-77 addresses 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. The LRA credits the Fire Water System Program to manage aging for steel piping and fittings in the fire protection system. The GALL Report recommends GALL AMP XI.M20, “Open-Cycle Cooling Water System,” to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The AMR line items also cite plant-specific note 5, indicating that the Fire Water System Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

The staff reviewed the applicant’s Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.6. In its review of components associated with Table 3.3-1, item 3.3.1-77, the staff noted that, in LRA Table 3.3.2-12, the applicant referenced GALL Report item VII.C1-5, which is for steel heat exchanger components exposed to raw water in the open-cycle cooling water system (service water system). The staff reviewed the GALL Report and noted that item VII.G-24 is for steel piping, piping components, and piping elements exposed to raw water in the fire protection system with the same aging effects and would have been a more appropriate reference, along with a reference to LRA Table 3.3.1, item 3.3.1-68. This GALL Report item recommends the Fire Water System Program to manage loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling of steel piping and piping components exposed to raw water. The staff finds the applicant's program acceptable to manage aging for these components because: (1) it includes functional testing, flow testing, and volumetric examinations to detect loss of material; and (2) the program is consistent with the GALL Report recommendations in item VII.G-24 for this material, environment, and aging effect combination.

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).

3.3.2.1.13 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-80 addresses stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water for loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The LRA credits the Periodic Inspection Program to manage aging effects for stainless steel eductors, heat exchangers and components, pump casings, piping and fittings, valve bodies, flow elements, hoses, thermowell, filter housing, orifices, and tanks in LRA Tables 3.3.2-5, 3.3.2-17, and 3.3.2-21. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR line items cite generic note E.

For those line items associated with generic note E, GALL AMP XI.M20 recommends preventive measures including proper selection of materials and coatings, periodic flushes and cleaning, and raw water chemistry control, as well as visual inspections and NDEs or condition monitoring of components exposed to open-cycle cooling water. Open-cycle cooling water is water that transfers heat from safety-related components to the ultimate heat sink. In its review of the LRA of components associated with item 3.3.1-80, for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage the aging effects of stainless steel heat exchangers and components, pump casings, piping and fittings, valve bodies, flow elements, hoses, thermowell, filter housing, orifices, and tanks exposed to raw water for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements of piping and its components to detect loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The staff also notes that the referenced components in the component cooling, heating water and heating steam, and radwaste systems are nonsafety-related, and in accordance with NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," use of a substitute program for the "Open-Cycle Cooling Water" program is appropriate provided it has the same inspection procedures and provides reasonable assurance that the components' intended functions will be maintained within the CLB for the period of extended operation. In its review of components associated with item 3.3.1-80, the staff finds the applicant's Periodic Inspection Program acceptable to manage aging effects for these components because it performs similar periodic visual inspections and wall thickness measurements that are appropriate to detect loss of material, thinning, and fouling.

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).

3.3.2.1.14 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-81 addresses copper alloy piping, piping components, and piping elements exposed to raw water for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Periodic Inspection Program to manage the aging effect for copper-Zn alloyed piping and fittings and valve bodies exposed to raw water in Table 3.3.2-13. The GALL Report recommends GALL AMP XI.M20, “Open-Cycle Cooling Water System,” to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M20 recommends preventive measures including proper selection of materials and coatings, periodic flushes and cleaning, and raw water chemistry control, as well as visual inspections and NDE testing for condition monitoring of components exposed to open-cycle cooling water. Open-cycle cooling water is water that transfers heat from safety-related components to the ultimate heat sink. In its review of the LRA of components associated with item 3.3.1-81 for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage the aging effects of copper-Zn alloy piping, fittings, and valve bodies exposed to raw water with visual and volumetric inspection methods for loss of material and fouling that could result in reduction of heat transfer.

The staff’s evaluation of the applicant’s Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements of piping and its components to detect loss of material and fouling. The staff also notes that components included in item 3.3.1-81 made of copper with less than 15 percent Zn are resistant to SCC, selective leaching, and pitting and crevice corrosion. The staff further notes that the referenced components in the fresh water system are not safety-related and in accordance with NUREG-1833, “Technical Bases for Revision to the License Renewal Guidance Documents,” use of a substitute program for the “Open-Cycle Cooling Water” program is appropriate provided it has the same inspection procedures and provides a reasonable assurance that the components’ intended functions will be maintained within the CLB for the period of extended operation. In its review of components associated with item 3.3.1-81, the staff finds the applicant’s proposal to manage aging using the Periodic Inspection Program acceptable because it includes similar periodic visual inspections of components and ultrasonic wall thickness measurements of piping and its components to detect loss of material, thinning, and fouling.

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).

3.3.2.1.15 Cracking Due to Stress Corrosion Cracking

LRA Table 3.3.1, item 3.3.1-90 addresses stainless steel and steel with stainless steel cladding piping, piping components, piping elements, tanks, and fuel storage racks exposed to treated borated water greater than 60 °C (140 °F) which are being managed for cracking due to stress corrosion cracking. In its review of components associated with item number 3.3.1-90 for which the applicant cited generic note A, the staff noted that the existing guidance in the SRP-LR and GALL Report does not adequately address aging management for loss of material and cracking in treated borated water environments, in that, boron should not be credited as a corrosion inhibitor. In teleconference calls held with the applicant on May 5 and 10, 2011, the staff discussed draft RAI 3.2.1.48 requesting that the applicant state how the effectiveness of the Water Chemistry Program will be verified for the aging management for loss of material and cracking in treated borated water.

By letter dated May 18, 2011, the applicant provided a supplement to its LRA to include a one-time inspection to verify the effectiveness of the Water Chemistry Program in treated borated water environments.

The staff finds the applicant's LRA supplement acceptable because: (1) the effectiveness of the Water Chemistry Program will be verified to ensure that significant degradation due to stress corrosion cracking is not occurring, and (2) the additional one-time inspection activity is applied to systems that are not consistent with the PWR reactor coolant environment (e.g., low dissolved oxygen), and thus would be expected to be more prone to stress corrosion cracking.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of components associated with item 3.3.1-90, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs acceptable because: (1) the Water Chemistry 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 (2) the One-Time Inspection Program includes a one-time visual inspection which is capable of detecting stress corrosion cracking of select components to verify the effectiveness of the Water Chemistry Program.

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).

3.3.2.1.16 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-91 addresses stainless steel and steel with stainless steel cladding piping, piping components, and piping elements exposed to treated borated water which are being managed for loss of material due to pitting and crevice corrosion. In its review of components associated with item number 3.3.1-91 for which the applicant cited generic note A, the staff noted that the existing guidance in the SRP-LR and GALL Report does not adequately address aging management for loss of material and cracking in treated borated water environments, in that, boron should not be credited as a corrosion inhibitor. In teleconference calls held with the applicant on May 5 and 10, 2011, the staff discussed draft RAI 3.2.1.48 requesting that the applicant state how the effectiveness of the Water Chemistry Program will be verified for the aging management for loss of material and cracking in treated borated water.

By letter dated May 18, 2011, the applicant provided a supplement to its LRA to include a one-time inspection to verify the effectiveness of the Water Chemistry Program in treated borated water environments.

The staff finds the applicant's LRA supplement acceptable because: (1) the effectiveness of the Water Chemistry Program will be verified to ensure that significant degradation due loss of material is not occurring, and (2) the additional one-time inspection activity is applied to systems that are not consistent with the PWR reactor coolant environment (e.g., low dissolved oxygen), and thus would be expected to be more prone to loss of material.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of components associated with item 3.3.1-91, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs acceptable because: (1) the Water Chemistry 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 (2) the One-Time Inspection Program includes a one-time visual inspection which is capable of detecting loss of material of select components to verify the effectiveness of the Water Chemistry Program.

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).

3.3.2.1.17 No Aging Effect Requiring Management

LRA Table 3.3.1, item 3.3.1-98 addresses steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air, which have no AERM. The LRA credits the Compressed Air Monitoring Program to manage the aging effect. Although the GALL Report recommends that no AMP is needed to ensure that these aging effects are adequately managed, the applicant credits the Compressed Air Monitoring Program to further verify that conditions do not change which could result in AERMs. The associated AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, but a different AMP is credited. Line items associated with steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dry air in LRA Table 3.3.2-6 also cite plant-specific note 1, which states that "the Compressed Air Monitoring Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination. The Compressed Air Monitoring Program is applied to confirm the internal environment remains sufficiently dry to preclude aging effects."

The staff's evaluation of the applicant's Compressed Air Monitoring Program is documented in SER Section 3.0.3.1.10. The staff notes that GALL Report item 3.3.1-98 does not recommend an AMP to manage steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air because there is not an AERM. The staff also notes that although no aging effect exists for this component, material, and environment combination, the applicant is crediting the Compressed Air Monitoring Program to verify the internal dry air or gas environment to ensure there are no AERMs. The staff further notes that the applicant includes line items to manage the loss of material due to pitting and crevice corrosion aging effects for steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to wet air, which also credits the Compressed Air Monitoring Program. In its review of components associated with item 3.3.1-98, the staff finds the applicant's proposal to manage aging using the Compressed Air Monitoring Program acceptable because: (1) there is no AERM for this component, material, and environment combination; (2) although the GALL Report recommends that no AMP is needed to ensure these aging effects are adequately managed, the applicant credits the Compressed Air Monitoring Program to further verify that conditions do not change which could result in AERMs; and (3) if conditions do change and the environment becomes wet air as opposed to dry air, the applicant has identified additional line items to manage the loss of material due to pitting and crevice corrosion aging effects, which are managed by the Compressed Air Monitoring Program.

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).

3.3.2.1.18 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.4.1, item 3.4.1-33 addresses stainless steel heat exchanger components exposed to raw water for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Periodic Inspection Program to manage aging effects for stainless steel pump casings, piping and fittings, valve bodies, and a sump screen in Tables 3.3.2-20 and 3.5.2-3. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E.

For those line items associated with generic note E, GALL AMP XI.M20 recommends preventive measures including proper selection of materials and coatings, periodic flushes and cleaning, and raw water chemistry control, as well as visual inspections and NDE testing for condition monitoring of components exposed to open-cycle cooling water. Open-cycle cooling water is water that transfers heat from safety-related components to the ultimate heat sink. In its review of the LRA of components associated with item 3.4.1-33 for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage the aging effects of stainless steel pump casings, piping and fittings, valve bodies, and a sump screen exposed to raw water for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements of piping and its components to detect loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The staff also notes that the equipment for floor drainage and radwaste systems and containment structure do not contain safety-related components exposed to open-cycle cooling water, so the use of the Open-Cycle Cooling Water Program would not be appropriate. In its review of components associated with item 3.4.1-33, the staff finds the applicant's Periodic Inspection Program acceptable to manage aging for these components because it performs similar periodic visual inspections and wall thickness measurements that are appropriate to detect loss of material, thinning, and fouling.

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).

3.3.2.1.19 Conclusion for AMRs Consistent with the GALL Report

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated 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 with the GALL Report AMRs. Therefore, the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.3.2.2 provides further evaluation of aging management, as recommended by the GALL Report, for the auxiliary systems components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- reduction of heat transfer due to fouling
- cracking due to SCC
- cracking due to SCC and cyclic loading
- hardening and loss of strength due to elastomer degradation
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and galvanic corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to wear
- loss of material due to cladding breach

- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues. In addition, the staff reviewed the applicant's further evaluations against the criteria 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 states fatigue is a TLAA as defined in 10 CFR 54.3. Furthermore, TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that the evaluation of metal fatigue as a TLAA for the chemical and volume control system is discussed in LRA Section 4.3 and the evaluation of crane load cycles as a TLAA for cranes and hoists is discussed in LRA Section 4.6.

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR Section 3.3.2.2.1, which state that fatigue of auxiliary systems components is a TLAA as defined in 10 CFR 54.3 and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff also reviewed LRA Section 3.3.2.2.1 and the AMRs discussed in this Section against the staff's AMR items for evaluating cumulative fatigue damage in PWR auxiliary designs, as given in AMR items 1 and 2 of the GALL Report, Volume 1, Table 3 and the AMR items in Section VII of the GALL Report, Volume 2, Revision 1 that derive from these GALL Report, Volume 1 AMR items.

With regard to LRA Table 3.3.1, item 3.3.1-1, the staff noted that GALL AMR item VII.B-2 identifies cumulative fatigue damage as an applicable aging effect for steel cranes or structural girders exposed to air and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included an applicable line item in LRA Table 3.3.2-9 for steel cranes or hoists consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of steel cranes or structural girders to be acceptable because it is consistent with the recommendations in SRP-LR Section 3.3.2.2.1. The staff evaluates the TLAA analysis for the steel cranes or hoists in SER Section 4.6.

With regard to LRA Table 3.3.1, item 3.3.1-2, the staff noted that GALL AMR items VII.E1-4, VII.E1-16, VII.E1-18, VII.E3-14, and VII.E3-17 identifies cumulative fatigue damage as an applicable aging effect for heat exchangers and piping, piping components, and piping elements and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included an applicable line item in LRA Table 3.3.2-2 for heat exchanger components, piping, fittings, and tanks that received implicit fatigue analysis calculations in accordance with design code requirements for ASME Code Section III Class 2 or 3 components or ANSI B31.1 components consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of piping, piping components, piping elements, and heat exchanger components to be acceptable because it is consistent with the recommendations in SRP-LR Section 3.3.2.2.1. The staff evaluates the TLAA analysis for the heat exchanger components, piping, fittings, and tanks in SER Section 4.3.

Based on the programs identified, 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 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).

3.3.2.2.2 Reduction of Heat Transfer Due to Fouling

LRA Section 3.3.2.2.2, associated with LRA Table 3.3.1, item 3.3.1-3, addresses reduction in heat transfer due to fouling in stainless steel heat exchanger tubes exposed to treated water. The applicant stated that this line item is not applicable because these components will be managed by LRA Table 3.4.1, item 3.4.1-9. The staff noted that this proposed item is associated with the further evaluation in SRP-LR Section 3.4.2.2.4, item 1, which addresses reduction in heat transfer due to fouling in stainless steel and copper alloy heat exchanger tubes exposed to treated water in the steam and power conversion systems. The staff also noted that the applicant is proposing to use the Water Chemistry and One-Time Inspection programs to manage aging for these components. The staff further noted that the proposed item 3.4.1-9 encompasses the same materials, components, environment, and aging effect and uses the same AMPs as item 3.3.1-3 and, therefore, finds the applicant's determination acceptable.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.2. For those line items that apply to LRA Section 3.3.2.2.2, 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).

3.3.2.2.3 Cracking Due to Stress-Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.3 against the criteria in SRP-LR Section 3.3.2.2.3.

(1) LRA Section 3.3.2.2.3 addresses cracking due to SCC, stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.3.2.2.3 states that cracking due to SCC could occur in the stainless steel piping, piping components, and piping elements of the BWR standby liquid control system that are exposed to sodium pentaborate solution greater than 60 °C (140 °F).

This line item is not applicable to the Salem units because they are PWRs. On this basis, the staff finds that the SRP-LR criteria do not apply to Salem.

(2) LRA Section 3.3.2.2.3, item 2 is referenced by LRA Table 3.3.1, item 3.3.1-5 and addresses stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60 °C (140 °F), which are being managed for cracking due to SCC by the Water Chemistry Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable to auxiliary systems because this component, material, environment, and aging effect/mechanism for auxiliary system components are managed within item 3.3.1-90 and uses the Water Chemistry Program to manage the aging effects.

The staff reviewed LRA Section 3.3.2.2.3, item 2 against the criteria in SRP-LR Section 3.3.2.2.3, item 2, which state that cracking due to SCC could occur in stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60 °C (140 °F). The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP and that the acceptance criteria are described in Branch Technical Position RLSB-1.

In its review of components associated with item 3.3.1-5, the staff noted the applicant relies on the Water Chemistry Program alone, whereas a plant-specific program in accordance with SRP-LR Appendix A.1 has a detection of aging effects program element which is not addressed in the Water Chemistry Program. In RAI 3.3.2.2-3 June 11, 2010, the staff requested that the applicant identify the method that will be used to detect cracking or provide justification for not performing activities that will detect cracking due to SCC in these components.

In its response dated July 8, 2010, the applicant stated that the further evaluation in Section 3.3.2.2.3, item 2 incorrectly referenced item 3.3.1-90, which is for components exposed to treated borated water. The applicant also stated that the associated components in auxiliary systems, which align with item 3.3.1-5, have been evaluated with the steam and power conversion systems through item 3.4.1-14 and associated Section 3.4.2.2.6. The applicant further stated that the programs to detect cracking for these components are the Water Chemistry and One-Time Inspection programs and that the LRA will be revised to indicate that there are no stainless steel heat exchanger components in the associated environment evaluated in auxiliary systems.

The staff finds the applicant's response acceptable because it corrected the inaccurate information in the LRA and notes that SRP-LR Section 3.4.2.2.6, which is referenced by item 3.4.1-14, recommends the same AMPs as those being proposed above by the applicant. The staff's review of LRA Sections 2.3.3 and 3.3 confirmed that the in-scope stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60 °C (140 °F) present in the auxiliary systems have been evaluated through item 3.4.1-14. The staff's concern described in RAI 3.3.2.2-3 is resolved and the staff finds the applicant's determination, that this item is not applicable, to be acceptable because the applicant provided further evaluation through the comparable item 3.4.1-14.

(3) LRA Section 3.3.2.2.3.3 is referenced by LRA Table 3.3.1, item 3.3.1-6 and addresses stainless steel diesel engine exhaust expansion joints exposed to diesel exhaust, which are being managed for SCC by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the program includes focused visual inspections to evaluate if material degradation is occurring, which could result in a loss of component intended function, due to exposure to the environmental condition.

The staff reviewed LRA Section 3.3.2.2.3.3 against the criteria in SRP-LR Section 3.3.2.2.3, item 3, which state that cracking due to SCC could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The SRP-LR recommends a plant-specific AMP to manage SCC. In addition, a further evaluation of the plant-specific program for these components is recommended to ensure that the aging effect is adequately managed. GALL Report item VII.H2-1 (AP-33) also recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed. The acceptance criteria for further evaluation of the plant-specific AMP are described in Branch Technical Position RSLB-1.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the program is acceptable because it requires focused visual inspections to ensure that the existing environmental conditions are not causing environmental degradation that could result in a loss of the component's intended function. In its review of components associated with item 3.3.1-6, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.3, item 3 by requiring visual inspection techniques which will be able to detect SCC.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.3.3 criteria. For those line items that apply to LRA Section 3.3.2.2.3.3, 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 will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.3. For those line items that apply to LRA Section 3.3.2.2.3, 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).

3.3.2.2.4 Cracking Due to Stress-Corrosion Cracking and Cyclic Loading

The staff reviewed LRA Section 3.3.2.2.4 against the criteria in SRP-LR Section 3.3.2.2.4.

(1) LRA Section 3.3.2.2.4, item 1 is referenced by LRA Table 3.3.1, item 3.3.1-7 and addresses stainless steel PWR non-regenerative heat exchanger components exposed to borated water, which are being managed by the Water Chemistry Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program, in conjunction with continuous monitoring for radioactivity on the shell side of the non-regenerative stainless steel heat exchangers, will be used to manage this aging effect.

The staff reviewed LRA Section 3.3.2.2.4, item 1 against the criteria in SRP-LR Section 3.3.2.2.4, item 1, which state that cracking due to SCC and cyclic loading could occur in stainless steel PWR non-regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F) in the chemical and volume control system. The SRP-LR also states that the existing AMP relies on monitoring and control of primary water chemistry in PWRs to manage the aging effects of cracking due to SCC and that the effectiveness of the water chemistry control program should be verified to ensure that cracking does not occur. The SRP-LR further states that an acceptable verification program includes temperature and radioactivity monitoring of the shell side water and ECT of tubes.

In its review of components associated with item 3.3.1-7, the staff noted the applicant relies on continuous monitoring for radioactivity on the shell side of the non-regenerative stainless steel heat exchangers to detect cracking due to SCC and cyclic loading and that this will not detect cracking before it has progressed through–wall, whereas the GALL Report recommends eddy current examination which would detect cracking before leakage occurs. By letter dated June 17, 2010, the staff issued RAI 3.3.2.2-1 requesting that the applicant identify the method that will be used to detect cracking before leakage occurs.

In its response dated July 15, 2010, the applicant stated that the LRA will be revised to add the One-Time Inspection Program for verifying the effectiveness of the Water Chemistry Program for the associated components. The applicant also stated that the One-Time Inspection Program will be revised to include ECT of stainless steel tubes in a non-regenerative heat exchanger normally exposed to treated borated water greater than 60 °C (140 °F). The staff finds the applicant's response acceptable because the inclusion of ECT of the associated components in the One-Time Inspection Program will be able to verify the effectiveness of the Water Chemistry Program by identifying cracking prior to the loss of intended function (pressure boundary). The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The staff finds the applicant's proposal to manage aging using the above programs acceptable because: (1) the Water Chemistry Program provides for periodic sampling to maintain contaminants at acceptable limits to mitigate cracking due to SCC and cyclic loading, and (2) the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by performing ECT of stainless steel tubes in a non-regenerative heat exchanger.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4 item 1 criteria. For those line items that apply to LRA Section 3.3.2.2.4 item 1, 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).

(2) LRA Section 3.3.2.2.4, item 2 is referenced by LRA Table 3.3.1, item 3.3.1-8 and addresses stainless steel PWR regenerative heat exchanger components exposed to borated water, which are being managed for cracking due to SCC and cyclic loading. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program will manage this aging effect in the chemical and volume control system and that the integrity of the regenerative heat exchanger is verified by continuous temperature monitoring. The applicant also stated that the One-Time Inspection Program includes inspections of other stainless steel components in this environment to verify the effectiveness of the Water Chemistry Program to manage cracking.

The staff reviewed LRA Section 3.3.2.2.4, item 2 against the criteria in SRP-LR Section 3.3.2.2.4, item 2, which state that cracking due to SCC and cyclic loading could occur in stainless steel PWR regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F). The SRP-LR also states that the existing AMP relies on monitoring and controlling primary water chemistry to manage this aging effect and that the effectiveness of the water chemistry control program should be verified to ensure that cracking does not occur. The SRP-LR further states that the GALL Report recommends a plant-specific AMP be evaluated to verify the absence of this aging effect and that acceptance criteria are described in Branch Technical Position RLSB-1.

In its review of components associated with item 3.3.1-8, the staff noted that the applicant is using the One-Time Inspection Program in lieu of a plant-specific program where periodic inspections are to be scheduled and that generic note A is assigned to the one-time inspection for the regenerative heat exchangers. In RAI 3.3.2.2-2 dated June 17, 2010, the staff requested that the applicant provide justification for using a one-time inspection in lieu of periodic inspections in a plant-specific program and the use of generic note A instead of generic note E when applying the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program.

In its response dated July 15, 2010, the applicant discussed the all-welded construction of the regenerative heat exchangers which prevents access to the internals without cutting and stated that the One-Time Inspection Program includes an inspection of a non-regenerative heat exchanger. The applicant also stated that a search of plant operating experience had not found any instances of tube leakage for the regenerative heat exchanger and that the One-Time Inspection Program provides the means to verify the effectiveness of the Water Chemistry Program without excessive radiological dose that the Periodic Inspection Program would require. The applicant further stated that generic note A was inadvertently used in conjunction with the One-Time Inspection Program and it revised the designation to generic note E.

The staff finds the applicant's response acceptable because, as discussed in GALL AMP XI.M32, "One-Time Inspection," a one-time inspection can be used to verify the system-wide effectiveness of an AMP that controls water chemistry, and the eddy current inspection of a non-regenerative heat exchanger in a similar environment will confirm that this aging effect is being adequately managed by the Water Chemistry Program. In addition, the applicant will correct the inadvertent use of generic note A for this item by revising the LRA to designate generic note E. The staff's concern described in RAI 3.3.2.2-2 is resolved.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The staff finds the applicant's proposal to manage aging using the above programs acceptable because: (1) the Water Chemistry Program provides for periodic sampling to maintain contaminants at acceptable limits to mitigate cracking due to SCC and cyclic loading and (2) the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by performing ECT of stainless steel tubes in a similar environment in a non-regenerative heat exchanger.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4, item 2 criteria. For those line items that apply to LRA Section 3.3.2.2.4, item 2, 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 3.3.2.2.4.3 refers to Table 3.3.1, item 3.3.1-9 and addresses cracking due to SCC and cyclic loading for the stainless steel high-pressure pump casings in the chemical and volume control system exposed to treated borated water. The LRA also states that the Water Chemistry Program and One-Time Inspection Program will be

implemented to manage the aging effect. The LRA further states that the Water Chemistry Program includes activities for monitoring and controlling the primary water chemistry.

The staff reviewed LRA Section 3.3.2.2.4.3 against the criteria in SRP-LR Section 3.3.2.2.4.3, which state that cracking due to SCC and cyclic loading could occur for the stainless steel pump casing for the PWR high-pressure pumps in the chemical and volume control system. The SRP-LR also states that the existing AMP relies on monitoring and control of the primary water chemistry to manage the aging effects of cracking due to SCC. The SRP-LR further states that the effectiveness of the water chemistry control program should be verified to ensure that cracking does not occur. The staff also noted that the GALL Report, under item VII.E1-7, recommends the water chemistry program to manage the aging effect. As the SRP-LR indicates, the GALL Report further recommends that a plant-specific program be evaluated to verify the absence of cracking due to SCC and cyclic loading.

The staff reviewed the LRA and identified in Table 3.1.1, item 3.1.1-9 and Table 3.3.2-2 that the applicant credited the Water Chemistry Program and One-Time Inspection Program to manage the cracking due to SCC and cyclic loading in the stainless steel pump casing. The staff also reviewed the applicant's Water Chemistry Program and One-Time Inspection Program. The staff's evaluations are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The applicant indicated that the One-Time Inspection Program includes a one-time inspection of more susceptible materials in potentially more aggressive environments to manage the aging effect. The staff finds that the credited programs are adequate to manage the aging effect because: (1) the Water Chemistry Program monitors the water chemistry control parameters against the established parameter limits and, if a parameter exceeds the limit, the program performs adequate actions such that the water chemistry control continues to mitigate the aging effect; (2) the One-Time Inspection Program includes a one-time inspection of selected components to verify the effectiveness of the Water Chemistry Program; and (3) the one-time inspection can ensure that significant degradation does not occur and the component's intended function is maintained during the period of extended operation. On the basis of its review, the staff finds that the applicant's AMR results are consistent with those under GALL Report, Volume 2, item VII.E1-7 and the applicant satisfied the acceptance criteria in SRP-LR Section 3.3.2.2.4.3.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4 criteria. For those items that apply to LRA Section 3.3.2.2.4, 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).

(4) LRA Section 3.3.2.2.4.4, associated with LRA Table 3.3.1, item 3.3.1-10, addresses cracking due to SCC and cyclic loading in high-strength bolting exposed to air with steam or water leakage. The applicant stated that this line item is not applicable because there is no high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed LRA Sections 2.3.3 and 3.3 and the UFSAR and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage is present in the auxiliary systems and, therefore, finds the applicant's determination acceptable.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4 criteria. For those line items that apply to LRA Section 3.3.2.2.4, 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).

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

(1) LRA Section 3.3.2.2.5.1 refers to LRA Table 3.3.1, item 3.3.1-11 and addresses elastomer components (door seals and flexible connections) in the auxiliary building ventilation, containment ventilation, control area ventilation, fuel handling ventilation, and switchgear and penetration area ventilation systems exposed to indoor air, which are being managed for hardening and loss of strength by the Periodic Inspection Program. The applicant addressed the further evaluation requirement by stating that the Periodic Inspection Program is used to manage aging effects of components that are not covered by other AMPs, including external and internal surfaces of non-steel components. The applicant also stated that the Periodic Inspection Program includes visual inspections and physical manipulation of elastomer components.

The staff reviewed LRA Section 3.3.2.2.5.1 against the criteria in SRP-LR Section 3.3.2.2.5.1, which state that hardening and loss of strength could occur for elastomer seals and components exposed to uncontrolled indoor air. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. In its review of components associated with LRA item 3.3.1-11 for which the applicant assigned generic note E, the staff noted that the Periodic Inspection Program is a plant-specific program that proposes to detect the aging of elastomer door seals and flexible connections through the use of visual inspections and physical manipulations. The staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because: (1) the program performs visual inspections and physical manipulations that are capable of detecting hardening and loss of strength in elastomer components, and (2) the program initiates corrective actions, implemented through the applicant's corrective program, if indications of age-related degradation are found.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.5.1 criteria. For those line items that apply to LRA Section 3.3.2.2.5.1, 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).

(2) LRA Section 3.3.2.2.5, item 2, associated with LRA Table 3.3.1, item 3.3.1-12, addresses hardening and loss of strength due to elastomer degradation in elastomer linings of the filters, valves, and ion exchangers in SFP cooling and cleanup systems exposed to treated water or to treated borated water. The applicant stated that this line item is not applicable because there are no elastomer lining components exposed to treated water that are subject to hardening and loss of strength due to elastomer degradation in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3

and the UFSAR and confirmed that no elastomer linings of the filters, valves, and ion exchangers in SFP cooling and cleanup systems exposed to treated water or to treated borated water within scope are present in the auxiliary systems and, therefore, finds the applicant's determination acceptable.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.5 criteria. For those line items that apply to LRA Section 3.3.2.2.5, 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).

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

LRA Section 3.3.2.2.6, referenced by LRA Table 3.3.1, item 3.3.1-13, addresses reduction of neutron-absorbing capacity and loss of material due to general corrosion in neutron-absorbing Boral spent fuel storage racks exposed to treated or borated water, which are being managed by the Boral Monitoring Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the plant-specific Boral Monitoring Program is used to mitigate reduction of neutron-absorbing capacity and loss of material aging effects. The applicant stated that the Water Chemistry Program will manage loss of material of the aluminum cladding of the Boral.

The staff reviewed LRA Section 3.3.2.2.6 against the criteria in SRP-LR Section 3.3.2.2.6, which state that reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur in the neutron-absorbing sheets of BWR and PWR spent fuel storage racks exposed to treated water or to treated borated water. The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed and that acceptance criteria are described in Branch Technical Position RLSB-1.

The staff's evaluation of the applicant's Boral Monitoring Program is documented in SER Section 3.0.3.3.5. In its review of components associated with item 3.3.1-13, the staff finds the applicant's proposal to manage aging using the Boral Monitoring and Water Chemistry Programs acceptable because: (1) the Water Chemistry Program is consistent with the GALL Report recommendations, and (2) the Boral Monitoring Program satisfies the acceptance criteria of the SRP-LR and uses inspection techniques (e.g., neutron attenuation, visual inspections, looking specifically for corrosion, weld cracks, or leaks) that will detect aging effects related to the neutron absorption and dimensional integrity.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.6 criteria. For those line items that apply to LRA Section 3.3.2.2.6, 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).

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

The staff reviewed LRA Section 3.3.2.2.7 against the criteria in SRP-LR Section 3.3.2.2.7

(1) LRA Section 3.3.2.2.7.1, referenced by LRA Table 3.3.1, item 3.3.1-14, addresses steel piping, piping components, and piping elements exposed to lubricating oil, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in steel piping, piping components, piping elements, tanks, and heat exchangers exposed to lubricating oil.

LRA Section 3.3.2.2.7.1, referenced by LRA Table 3.3.1, item 3.3.1-15, addresses steel RCP oil collection system piping, tubing, and value bodies exposed to lubricating oil, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in the RCP oil collection system steel piping exposed to lubricating oil in the fire protection system.

LRA Section 3.3.2.2.7.1, referenced by LRA Table 3.3.1, item 3.3.1-16, addresses the steel RCP oil collection system tank exposed to lubricating oil, which is being managed for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through the examination of susceptible locations in the RCP oil collection system steel tank exposed to lubricating oil in the fire protection system.

The staff reviewed LRA Section 3.3.2.2.7.1 against the criteria in SRP-LR Section 3.3.2.2.7, item 1, which state that loss of material due to general, pitting, and crevice corrosion could occur in steel piping, piping components, and piping elements, including the tubing, valves, and tanks in the RCP oil collection system, exposed to lubricating oil (as part of the fire protection system). The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.11 and 3.0.3.1.11, respectively. In its review of components associated with items 3.3.1-14, 3.3.1-15, and 3.3.1-16, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (1) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report; and (2) the applicant stated that the One-Time

Inspection Program will be used to examine steel piping, piping components, and piping elements; steel RCP oil collection system piping, tubing, and valve bodies; and the steel RCP oil collection system tank to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.7, item 1 and, therefore, the applicant's AMR is consistent with GALL Report items VII.C1-17, VII.C2-13, VII.E1-19, VII.F3-19, VII.H2-20, VII.G-26, and VII.G-27.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 1 criteria. For the line items that apply to LRA Section 3.3.2.2.7.1, 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).

(2) LRA Section 3.3.2.2.7.2 addresses loss of material due to general, pitting, and crevice corrosion, stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.3.2.2.7.2 states that loss of material due to general, pitting, and crevice corrosion may occur in steel piping, piping components, and piping elements in the BWR reactor water cleanup and shutdown cooling systems exposed to treated water.

The Salem units are PWRs and do not have reactor water cleanup and shutdown cooling systems. On this basis, the staff finds that this item is not applicable to Salem.

(3) LRA Section 3.3.2.2.7.3 refers to LRA Table 3.3.1, item 3.3.1-18 and addresses stainless steel and steel diesel engine exhaust piping and components exposed to diesel exhaust, which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the programs include visual inspections to evaluate if material degradation occurs with the result in a loss of component intended function, as a result of exposure to the environmental condition.

The staff reviewed LRA Section 3.3.2.2.7.3 against the criteria in SRP-LR Section 3.3.2.2.7, item 3, which state that loss of material could occur in steel and stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The SRP-LR recommends a plant-specific AMP to manage the loss of material effect. In addition, a further evaluation of the plant-specific program for these components is recommended to ensure that the aging effect is adequately managed. GALL Report item VII.H2-2 (A-27) also recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed. The acceptance criteria for further evaluation of the plant-specific AMP are described in Branch Technical Position RSLB-1.

The staff's evaluations of the applicant's Periodic Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs are documented in SER Sections 3.0.3.3.2 and 3.0.3.1.15, respectively. The staff notes that the programs are acceptable because they require visual inspections to ensure that the existing environmental conditions are not causing environmental degradation that could result in a loss of the component's intended function. In its review of components associated with item 3.3.1-18, the staff finds the applicant's proposal to manage aging using the Periodic Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs acceptable because it satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.7, item 3 by requiring visual inspection techniques which will be able to detect loss of material due to general (steel only), pitting, and crevice corrosion.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 3 criteria. For those line items that apply to LRA Section 3.3.2.2.7.3, 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 will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7 criteria. For those line items that apply to LRA Section 3.3.2.2.7, 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).

3.3.2.2.8 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Section 3.3.2.2.8 refers to LRA Table 3.3.1, item 3.3.1-19 and addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping, piping components, and piping elements, with or without coating or wrapping, buried in soil, which will be managed by the Buried Piping Inspection Program. The applicant also stated that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in the steel penetration sleeves exposed to groundwater and soil between the containment structure and fuel handling building will be managed by the Buried Non-Steel Piping Inspection Program.

The staff reviewed LRA Section 3.3.2.2.8 against the criteria in SRP-LR Section 3.3.2.2.8, which state that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion could occur in steel piping, piping components, and piping elements, with or without coating or wrapping, in a soil environment. The SRP-LR also states that the effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

The staff reviewed the LRA AMR items associated with LRA Table 3.3.1, item 3.3.1-19 and noted that for the items that are consistent with the GALL Report for material, environment, and aging effect but a different AMP is credited (generic note E) in Tables 3.5.2-3 and 3.5.2-5, the applicant will use the Buried Non-Steel Piping Inspection Program to manage the loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion for the steel penetration sleeves in the containment structure and the fuel handling building. The applicant also included plant-specific notes 9 and 11 (depending on table number). Both of these notes state, "The Buried Non-Steel Piping Inspection Program is substituted to manage the aging effect(s) applicable for this component type, material, and environment combination. The buried carbon steel sleeve will be inspected in conjunction with the associated buried stainless steel bellows assembly located between the Fuel Handling Building and the Containment Building." The staff further reviewed the applicant's Buried Non-Steel Piping Inspection Program, which is evaluated in SER Section 3.0.3.3.4. The staff finds the program acceptable because in conjunction with the Buried Non-Steel Piping Inspection Program, the applicant stated that it will perform an opportunistic or focused visual inspection of this specific component once in the 10-year period prior to the period of extended operation and again in each 10-year period after entry into the period of extended operation, which are capable of detecting the AERM.

The staff reviewed the LRA AMR items associated with LRA Table 3.3.1, item 3.3.1-19 and notes that for the steel tanks in the fire protection system which cite generic note E in Table 3.3.2-12, the applicant will use the Aboveground Steel Tanks Program to manage the loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The staff reviewed the applicant's Aboveground Steel Tanks Program, which is evaluated in SER Section 3.0.3.2.7. The staff finds the use of the Aboveground Steel Tanks Program acceptable because it requires periodic visual inspections of the accessible tank outer surface and the grout or sealant at the interface between the tank base and its foundation and wall-thickness measurements of the inaccessible tank bottom external surface by UT to ensure that the loss of material aging effect will be adequately managed and thus is consistent with GALL AMP XI.M29, "Aboveground Steel Tanks."

The staff reviewed the LRA AMR items associated with LRA Table 3.3.1, item 3.3.1-19 and noted that for the steel penetration sleeves and steel piles in the service water intake which cite generic note E in Table 3.5.2-13, the applicant will use the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to manage the loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The staff reviewed the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and its evaluation is documented in SER Section 3.0.3.2.16. The staff finds the use of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because it is designed to detect degradations and take corrective actions to ensure that the aging effects associated with water-control structures will be adequately managed.

The staff notes that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is a more appropriate AMP to monitor penetration sleeves in a groundwater/soil environment because the items are not pressure boundary components; however, due to potential accessibility constraints associated with the penetration sleeves being located in a groundwater/soil environment, the staff is unclear how the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, which is primarily a visual-based program, will be used to address the structure/aging effect combinations during the period of extended operation. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-02 requesting that the applicant describe how the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program meets or exceeds the requirements of the GALL Report recommended programs and how the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be used to manage carbon steel penetration sleeves in a groundwater/soil environment for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion during the period of extended operation. The applicant was also requested to discuss surveillance and preventive measure requirements.

In its response dated July 8, 2010, the applicant stated that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented as part of the Structures Monitoring Program, which includes periodic inspection from the indoor side of the wall of the penetration sleeves that are located below grade. The applicant also stated that the penetration sleeves are installed in concrete walls and the majority of the sleeve is located within the wall, while a small portion may protrude past the wall surface and into a soil environment. Most of the sleeve is protected on both the outer and inner surface by concrete, grout, or elastomer seal material. The applicant further stated that potential degradation of the small portion of the steel sleeve that protrudes past the exterior wall surface and is subject to the groundwater/soil environment will not impact the intended function given that most of the sleeve is protected on both the inner and outer surface and thus, degradation of this area of the sleeve is unlikely to penetrate to a wall depth sufficient to impact the intended function. The applicant stated that the Structures Monitoring Program includes inspections of the penetration seals and the associated sleeves on a 5-year interval. These inspections will detect material degradation or indications of seal leakage prior to loss of intended function.

The staff reviewed the applicant's response and noted that the penetration sleeves are structural components embedded in concrete and that the buried portion is not reasonably accessible for inspection. Visual inspections from the inside of the wall, on a 5-year frequency, will be able to detect degradation prior to a loss of intended function. Based on its review, the staff finds the applicant's aging management approach acceptable because the Structures Monitoring Program includes appropriate inspections to detect degradation of the penetration sleeves prior to a loss of intended function.

The staff finds the use of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing the aging effects associated with these penetration sleeves acceptable for the reasons as stated in the staff's evaluation of the applicant's response to RAI 3.5.2.1-02.

The staff reviewed the LRA AMR items associated with LRA Table 3.3.1, item 3.3.1-19 and noted that for the steel piles in the containment structure, fire pump house, office building, service building, shoreline protection and dike, switchyard, and yard structures; for the steel penetration sleeves in the auxiliary building, pipe tunnel, and turbine building; for the galvanized steel penetration sleeves in the turbine building; and for galvanized conduit in the switchyard which cite generic note E in Tables 3.5.2-1, 3.5.2-3, 3.5.2-4, 3.5.2-6, 3.5.2-8, 3.5.2-11, 3.5.2-14, 3.5.2-15, 3.5.2-16, and 3.5.2-17, the applicant will use the Structures Monitoring Program to manage the loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The staff further reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff finds the use of the Structures Monitoring Program acceptable because it requires periodic sampling, testing, and analysis of groundwater chemistry and periodic inspections of the components to ensure that the aging effects will be adequately managed. The staff finds the applicant's management for loss of material due to pitting, crevice, and microbiologically-influenced corrosion acceptable because the applicant satisfied the acceptance criteria in SRP-LR Section 3.3.2.2.8 and, therefore, the applicant's AMR results are consistent with the one under GALL Report items VII.C1-18, VII.G-25, and VII.H1-9.

For piles as contained in the above AMR line items, LRA Section 3.5.2.2.2.2, item 3 states that:

> Studies have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the oxygen deficiency in soil at a few feet below grade. Piles driven into disturbed soil, have been shown to experience only minor to moderate corrosion. In either case the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557.

> The Groups 1, 3, 4, and 5 structures are monitored under the Structures Monitoring Program for cracks and distortion due to increased stress levels from settlement.

The staff's review of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The LRA states that degradation of piles will manifest itself in settlement distortion or cracking of concrete, and accessible concrete examinations will detect cracks and distortion of the structures. The staff finds the use of the Structures Monitoring Program acceptable for managing the aging effects associated with these piles because the program inspects the concrete structures for indications of deterioration and distress, including cracking as defined in ACI 201.1R at a frequency not to exceed 5 years.

The staff notes that for penetration seals as contained in the above AMR line items, the Structures Monitoring Program is a more appropriate AMP to monitor these items because they are not pressure boundary components; however, due to potential accessibility constraints associated with the penetration sleeves and seals being located in a groundwater/soil environment, the staff is unclear how the Structures Monitoring Program, which is primarily a visual-based program, will be used to address the structure/aging effect combinations during the period of extended operation. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-01 requesting that the applicant describe how the Structures Monitoring Program meets the GALL Report recommended programs and how the AMP will be used to manage the aging effects, including a discussion of preventive measure requirements.

In its response dated July 8, 2010, the applicant stated that the penetration sleeves were aligned to GALL Report item 3.3.1-19 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination; the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report and that the recommended GALL Report programs are not applicable for aging management of the penetration sleeves. The applicant also stated that the penetration sleeves are installed in concrete walls and the majority of the sleeve is located within the wall, while a small portion may protrude past the wall surface and into a soil environment and that most of the sleeve is protected on both the outer and inner surface by concrete, grout, or elastomer seal material. The applicant further stated that potential degradation of the small portion of the steel sleeve that protrudes past the exterior wall surface and is subject to the groundwater/soil environment will not impact the intended function given that most of the sleeve is protected on both the inner and outer surface and thus, degradation of this area of the sleeve is unlikely to penetrate to a wall depth sufficient to impact the intended function. The applicant stated that the Structures Monitoring Program includes inspections of the penetration seals and the associated sleeves on a 5-year interval. These inspections will detect material degradation or indications of seal leakage prior to loss of intended function. The applicant also stated that for the buried conduit, the switchyard is the only structure that contains sections of inaccessible buried galvanized steel conduit within the scope of license renewal, extending from underground duct banks to manhole wall penetrations. The applicant further stated that periodic inspections of the penetrations and conduit ends will detect the presence of any water leakage, which would signify degradation of the conduit, prior to loss of intended function of the contained cable and in addition, the conduit will be inspected opportunistically when made accessible during maintenance activities.

The staff reviewed the applicant's response and notes that the penetration sleeves are structural components embedded in concrete and that the buried portion is not reasonably accessible for inspection. Visual inspections from the inside of the wall, on a 5-year frequency, will be able to detect degradation prior to a loss of intended function. Based on its review, the staff finds the applicant's aging management approach acceptable because the Structures Monitoring Program includes appropriate inspections to detect degradation of the penetration sleeves prior to a loss of intended function and the conduit will be inspected by checking for the presence of water or opportunistically during maintenance activities. The staff notes that the SRP-LR does not typically allow aging management to occur via detection of a failure of a component, but given the inaccessibility of the conduit and the fact that short term exposure of intact cable to moisture will not result in immediate failure, the staff finds it to be an acceptable alternative. The staff's concern described in RAI 3.5.2.1-01 is resolved.

The staff finds the use of the Structures Monitoring Program for managing the aging effects associated with these penetration sleeves acceptable for the reasons as stated in the staff's evaluation of the applicant's response to RAI 3.5.2.1-01.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.8 criteria. For those items that apply to LRA Section 3.3.2.2.8, 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 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).

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

The staff reviewed LRA Section 3.3.2.2.9 against the criteria in SRP-LR Section 3.3.2.2.9.

(1) LRA Section 3.3.2.2.9, item 1 refers to Table 3.3.1, item 3.3.1-20 and addresses steel piping, piping components, piping elements, and tanks exposed to fuel oil, which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling in the steel piping, piping components, piping elements, and tanks exposed to fuel oil in the fuel oil system will be managed by the Fuel Oil Chemistry and One-Time Inspection programs.

    The staff reviewed LRA Section 3.3.2.2.9, item 1 against the criteria described in SRP-LR Section 3.3.2.2.9, item 1, which state that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The SRP-LR also states that the AMP relies on monitoring and control of fuel oil contamination to mitigate degradation. The SRP-LR further states that a one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or progressing very slowly such that the component's intended function will be maintained during the period of extended operation. The GALL Report, under item VII.H1-10, recommends managing the aging effect using the Fuel Oil Chemistry Program augmented by the One-Time Inspection Program to verify the effectiveness of the fuel oil chemistry control.

    The staff reviewed the applicant's Fuel Oil Chemistry and One-Time Inspection programs and its evaluations are documented in SER Sections 3.0.3.2.8 and 3.0.3.1.11, respectively. The applicant stated that the One-Time Inspection Program includes: (1) determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience; (2) identification of inspection locations based on the aging effect; (3) selection of the examination technique with acceptance criteria; and (4) evaluation of the results including the need for additional inspections or other corrective actions. The staff finds the credited programs acceptable to manage aging for these components because: (1) the Fuel Oil Chemistry Program will assure that contaminates are maintained at acceptable levels in fuel oil and identify the actions required if the fuel oil contaminates exceed limits, and (2) the One-Time Inspection Program will include a one-time inspection of selected components at appropriate locations (e.g., low or stagnant flow areas) to verify the effectiveness of the Fuel Oil Chemistry Program for managing the effects of aging due to the potential corrosion mechanisms.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.9, item 1 criteria. For those items that apply to LRA Section 3.3.2.2.9, item 1, the staff determines that the LRA is consistent with the GALL Report and 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).

(2) LRA Section 3.3.2.2.9.2, referenced by LRA Table 3.3.1, item 3.3.1-21, addresses steel heat exchanger components exposed to lubricating oil, which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable because there are no steel heat exchanger components exposed to lubricating oil in the auxiliary systems.

The staff reviewed LRA Section 3.3.2.2.9.2 against the criteria in SRP-LR Section 3.3.2.2.9, item 2, which state that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel heat exchanger components exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lube Oil Chemistry Control Program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the UFSAR to verify that there are no steel heat exchanger components exposed to lubricating oil in the auxiliary systems.

Based on information in the UFSAR, the staff confirmed that the applicant's plant does not have steel heat exchanger components exposed to lubricating oil in the auxiliary systems. Therefore, the staff finds that this item is not applicable.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.9 criteria. For those line items that apply to LRA Section 3.3.2.2.9, 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).

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria in SRP-LR Section 3.3.2.2.10.

(1) LRA Section 3.3.2.2.10.1, associated with LRA Table 3.3.1, item 3.3.1-22, addresses pitting and crevice corrosion in steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water and treated borated water. The applicant stated that this line item is not applicable because the applicant's auxiliary systems do not contain steel piping with elastomer lining or steel piping with stainless steel cladding exposed to treated water. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that no steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water and treated borated water within scope are present in the auxiliary systems and, therefore, finds the applicant's determination acceptable.

(2) LRA Section 3.3.2.2.10.2, referenced by LRA Table 3.3.1, item 3.3.1-24, addresses stainless steel piping, piping components, piping elements, and tanks exposed to treated water which are being managed for pitting and crevice corrosion by the Water Chemistry Program. The GALL Report recommends that the effectiveness of the chemistry control program be verified, and a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the Water Chemistry and One-Time Inspection programs to manage the loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, piping elements, and tanks in the chemical and volume control, reactor coolant, and containment spray systems. The staff notes that the SRP-LR references both items 3.3.1-23 and 3.3.1-24. The staff also notes that item 3.3.1-23 is not applicable to the Salem units because they are PWRs and item 3.3.1-23 applies only to BWRs.

    The staff reviewed LRA Section 3.3.2.2.10.2 against the criteria in SRP-LR Section 3.3.2.2.10, item 2, which state that loss of material due to pitting and crevice corrosion could occur for stainless steel and aluminum piping, piping components, and piping elements and for stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water. The SRP-LR also states that the existing AMP relies on monitoring and control of water chemistry to manage the aging effects of loss of material from pitting and crevice corrosion. Furthermore, the SRP-LR states that the GALL Report recommends a one-time inspection of selected components at susceptible locations as an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

    The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The staff notes that the applicant stated that its primary cycle and secondary cycle water programs are consistent with the EPRI guidelines recommended by the GALL Report. The staff also notes that the applicant stated that its Water Chemistry Program includes periodic sampling of primary and secondary water for detrimental contaminants specified in the EPRI water chemistry guidelines. The staff further notes that the applicant's One-Time Inspection Program will use visual and volumetric inspection techniques performed per ASME Code standards to confirm the effectiveness of the Water Chemistry Program at mitigating the effects of aging. In its review of components associated with item 3.3.1-24, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because the Water Chemistry Program will mitigate loss of material due to pitting and crevice corrosion by managing the ingress of contaminants into the systems below the levels known to cause pitting and crevice corrosion. Furthermore, the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program in low flow areas, such that the component's intended function will be maintained during the period of extended operation.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10.2 criteria. For those line items that apply to LRA Section 3.3.2.2.10, item 2, 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 3.3.2.2.10.3 refers to LRA Table 3.3.1, item 3.3.1-25 and addresses copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external), which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Periodic Inspection Program will be implemented to manage loss of material due to pitting and crevice corrosion of the copper alloy HVAC piping, piping components, and piping elements exposed to wetted air or gas in the auxiliary building ventilation, chilled water, control area ventilation, and the heating water and heating steam systems. The applicant stated that the wetted air or gas environment assumed for these components includes the potential for wetting due to condensation. The applicant also stated that the Periodic Inspection Program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

The staff reviewed LRA Section 3.3.2.2.10.3 against the criteria in SRP-LR Section 3.3.2.2.10, item 3, which state that loss of material due to pitting and crevice corrosion could occur for copper alloy HVAC piping, piping components, and piping elements exposed to condensation. The SRP-LR also states that the reviewer reviews the applicant's proposed program on a case-by-case basis to ensure that an adequate program will be in place for the management of these aging effects.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the applicant is using the Periodic Inspection Program to manage loss of material due to pitting and crevice corrosion for copper alloy HVAC piping, piping components, and piping elements exposed to condensation by conducting visual inspection of copper alloy HVAC piping, piping components, and piping elements exposed to condensation to detect pitting and crevice corrosion. In its review of components associated with item 3.3.1-25, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.10, item 3 by requiring visual inspection techniques which will be able to detect loss of material due to pitting and crevice corrosion.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.10, item 3 criteria. For those line items that apply to LRA Section 3.3.2.2.10.3, 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).

(4) LRA Section 3.3.2.2.10.4, referenced by LRA Table 3.3.1, item 3.3.1-26, addresses copper alloy piping, piping components, and piping elements exposed to lubricating oil, which are being managed for loss of material due to pitting and crevice corrosion by the Lubricating Oil and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in copper alloy heat exchanger components exposed to lubricating oil in the component cooling system.

The staff reviewed LRA Section 3.3.2.2.10.4 against the criteria in SRP-LR Section 3.3.2.2.10, item 4, which state that loss of material due to pitting and crevice corrosion could occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.3.1-26, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (1) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (2) the applicant stated that the One-Time Inspection Program will be used to examine copper alloy piping, piping components, and piping elements to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.10, item 4 and, therefore, the applicant's AMR is consistent with the GALL Report items VII.C1-8, VII.C2-5, VII.E1-12, VII.G-11, and VII.H2-10.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 4 criteria. For the line items that apply to LRA Section 3.3.2.2.10.4, 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).

(5) LRA Section 3.3.2.2.10.5 refers to LRA Table 3.3.1, item 3.3.1-27 and addresses HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and components exposed to condensation, which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Periodic Inspection Program will be implemented to manage loss of material due to pitting and crevice corrosion of the stainless steel and aluminum HVAC ducting and ducting components, piping, piping components, and piping elements exposed to wetted air in the auxiliary building ventilation, chemical and volume control, component cooling, compressed air, containment spray, containment ventilation, control area ventilation, EDGs and auxiliaries, fuel handling ventilation, radioactive drain, reactor coolant, residual heat removal, safety injection, service water, service water ventilation, and switchgear and penetration area ventilation systems. The applicant stated that the wetted air or gas environment assumed for these components includes the potential for wetting due to condensation. The applicant also stated that the Periodic Inspection Program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

By letter dated June 25, 2010, the staff issued RAI 3.3.2.2.10.6-01 related to the applicant's Fire Protection Program. The RAI requested that the applicant provide justification for how the Fire Protection Program will adequately manage the aging effect of loss of material due to pitting and crevice corrosion. In its response dated July 21, 2010, the applicant stated that aluminum piping, piping components, and piping elements in the fire protection system were incorrectly identified as being in a wetted environment. As a result of the newly applied environment, the applicant has determined that the aging effect no longer applies. The staff's evaluation of the RAI response is documented in SER Section 3.3.2.2.10.6.

The staff reviewed LRA Section 3.3.2.2.10.5 against the criteria in SRP-LR Section 3.3.2.2.10, item 5, which state that loss of material due to pitting and crevice corrosion could occur for HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and components exposed to condensation. The SRP-LR also states that the reviewer conducts an evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed and that acceptance criteria are described in Branch Technical Position RLSB-1.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the applicant is using the Periodic Inspection Program to manage loss of material due to pitting and crevice corrosion for HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and components exposed to condensation by conducting visual inspections to detect pitting and crevice corrosion. In its review of components associated with item 3.3.1-27, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.10, item 5 by requiring visual inspection techniques in the Periodic Inspection Program which will be able to detect loss of material due to pitting and crevice corrosion.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.10, item 5 criteria. For those line items that apply to LRA Section 3.3.2.2.10.5, 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)

(6) LRA Section 3.3.2.2.10, item 6 is associated with Table 3.3-1, item 3.3.1-28 and addresses copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation, which are being managed for loss of material due to pitting and crevice corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that these components are managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection, Compressed Air Monitoring, Fire Protection, or Fire Water System programs.

The staff reviewed LRA Section 3.3.2.2.10, item 6, against the criteria in SRP-LR Section 3.3.2.2.10, item 6, which state that loss of material due to pitting and crevice corrosion could occur for copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation. The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.5. In its review of components associated with item 3.3.1-28, the staff noted that the applicant credited the Fire Protection Program to manage loss of material for copper alloy spray nozzles, piping and components, and valve bodies exposed to wetted air or gas in LRA Table 3.3.2-12. The staff also notes that the Fire Protection Program includes visual inspections of fire barriers and the external surfaces of the halon and CO_2 systems and performance testing of the diesel-driven fire pump fuel supply lines. The staff further notes that the description of the Fire Protection Program does not include criteria for inspections of the internal surfaces of components which could detect loss of material for the copper alloy spray nozzles, piping and components, and valve bodies exposed to wetted air or gas listed in LRA Table 3.3.2-12.

By letter dated June 25, 2010, the staff issued RAI 3.3.2.2.10.6-01 requesting that the applicant justify how the Fire Protection Program will adequately manage loss of material for these copper alloy components.

In its response dated July 21, 2010, the applicant stated that the halon and CO_2 dispersion systems contain copper alloy piping, fittings, and valves between the isolation valves and open spray nozzles that are exposed to the same environment as the external surfaces. The applicant also stated that the environment was conservatively listed as wetted air or gas, but that these components are not subject to internal condensation. The applicant further stated that the CO_2 dispersion system aluminum odorizer is also downstream of the isolation valves and not subject to internal condensation. As a result, the applicant revised the AMR line items for the aluminum odorizer and copper alloy piping, fittings, and valve bodies that credited the Fire Protection Program to change the environment to indoor air, change the aging effects to none, and change the AMP to none. The AMR line item for the aluminum odorizer was revised to reference item 3.2.1-50 and cite generic note A. The AMR line item for the copper alloy piping and fittings was revised to reference item 3.4.1-41 and cite generic note A. The AMR line items for valve bodies were revised to reference item 3.2.1-53 and cite generic note A. The staff notes that the new line items referenced correspond with appropriate GALL Report items that recommend that there are no AERMs for this material and environment combination. The staff finds the applicant's response to RAI 3.3.2.2.10.6-01 acceptable because: (1) the internal environment for components downstream from the isolation valves in the halon and CO_2 fire suppression systems should be the same as the external environment; (2) the external environment for the halon and CO_2 fire suppression systems is indoor air, which is not expected to contribute to corrosion of these components; (3) the applicant has chosen appropriate alternate line items that recommend no aging effects for these components when exposed to an indoor air environment; and (4) the applicant has made the corresponding revisions to the LRA.

During the applicant's review of items in LRA Table 3.3.2-12, the applicant stated that it incorrectly included AMR results for copper alloy spray nozzles in its foam fire suppression system for the gas turbine facility, which is not within the scope of license renewal. In its response to RAI 3.3.2.2.10.6-01, the applicant revised LRA Table 3.3.2-12 to remove the two AMR results for the copper alloy foam system spray nozzles. The staff finds the deletion of the foam system spray nozzles acceptable because the foam system associated with the gas turbine facility is not within the scope of license renewal and, therefore, the components do not require an AMP. The staff's concern described in RAI 3.3.2.2.10.6-01 is resolved.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.6. In its review of components associated with item 3.3.1-28, the staff noted that the applicant credited the Fire Water System Program to manage loss of material for sprinkler heads and valve bodies in LRA Table 3.3.2-12. The staff also notes that the Fire Water System Program manages aging effects for the water-based fire protection system and associated components through the use of periodic inspections, monitoring, and performance testing and that the applicant stated an enhancement to the program to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5-3.1.1. The applicant stated that these inspections will be performed by the 50-year in service date and every 10 years thereafter. The staff finds the applicant's Fire Water System Program acceptable to manage loss of material due to pitting and crevice corrosion for these components because: (1) the copper alloy sprinkler heads will be replaced or inspections will be performed consistent with GALL AMP XI.M27 and NFPA-25, and (2) the copper alloy valve bodies will be inspected and be part of the monitoring program consistent with GALL AMP XI.M27.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. In its review of components associated with item 3.3.1-28, the staff noted that the applicant credited the Periodic Inspection Program to manage loss of material for copper alloy heat exchanger components in LRA Table 3.3.2-3 and copper alloy valve bodies in LRA Table 3.3.2-11. The staff also notes that the Periodic Inspection Program includes provisions for visual inspection of stainless steel, aluminum, copper alloy, and elastomer components and ultrasonic wall thickness measurements to detect loss of material. The staff finds the applicant's Periodic Inspection Program acceptable to manage loss of material due to pitting and crevice corrosion for copper alloy heat exchanger components and valve bodies because: (1) visual inspections will be performed on component surfaces that are either normally accessible or made accessible during periodic component disassembly, and (2) wall thickness measurements will be performed on a representative sample of piping locations selected from systems within the scope of this program that are not normally opened for maintenance.

The staff reviewed the applicant's Compressed Air Monitoring Program and its evaluation is documented in SER Section 3.0.3.1.10. In its review of components associated with item 3.3.1-28, the staff noted that the applicant credited the Compressed Air Monitoring Program to manage loss of material for copper alloy valve bodies in LRA Table 3.3.2-6. The staff also notes that the Compressed Air Monitoring Program includes leakage testing and inspections of air system components and air quality checks at various locations in the system to ensure that dew point, particulates, lubricant content, and contaminants are kept within the limits specified in ANSI/ISA 7.0.01-1996. The staff finds the applicant's Compressed Air Monitoring Program acceptable to manage loss of material for these components because air quality checks and periodic inspections will mitigate and detect corrosion prior to loss of intended function.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10.6 criteria. For those line items that apply to LRA Section 3.3.2.2.10.6, 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).

(7) LRA Section 3.3.2.2.10.7 refers to Table 3.3.1, item 3.3.1-29 and addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this item is not applicable because there are no stainless steel piping, piping components, and piping elements buried in soil in the auxiliary systems. The staff reviewed the LRA AMR items and information in the UFSAR associated with Table 3.3.1, item 3.3.1-29 and confirms that there are no stainless steel piping, piping components, and piping elements exposed to soil in the auxiliary systems and subjected to loss of material due to pitting and crevice corrosion. Therefore, the staff finds the applicant's determination that LRA Table 3.3.1, item 3.3.1-29 is not applicable acceptable.

(8) LRA Section 3.3.2.2.10.8 addresses loss of material due to pitting and crevice corrosion, stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.3.2.2.10.8 states that loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, and piping elements of the BWR standby liquid control system exposed to sodium pentaborate solution.

The Salem units are PWRs and do not have a standby liquid control system. Therefore, the staff agrees that this item is not applicable to Salem.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10 criteria. For those line items that apply to LRA Section 3.3.2.2.10, 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).

3.3.2.2.11 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion

The staff reviewed LRA Section 3.3.2.2.11 against the criteria in SRP-LR Section 3.3.2.2.11.

LRA Section 3.3.2.2.11 addresses loss of material due to pitting, crevice, and galvanic corrosion, stating that this aging effect is not applicable to the Salem units, which are PWRs.

SRP-LR Section 3.3.2.2.11 states that loss of material due to pitting, crevice, and galvanic corrosion may occur in copper alloy piping, piping components, and piping elements exposed to treated water.

This item pertains to loss of material in copper alloy auxiliary system components exposed to a BWR treated water environment. The Salem units are PWRs; therefore, the staff agrees that this item is not applicable to Salem.

Based on the above, the staff concludes that SRP-LR Section 3.3.2.2.11 criteria do not apply.

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.12 against the criteria in SRP-LR Section 3.3.2.2.12.

(1) LRA Section 3.3.2.2.12, item 1, refers to Table 3.3.1, item 3.3.1-32 and addresses stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil, which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to pitting, crevice, and microbiologically-influenced corrosion in the stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil in the fuel oil system will be managed by the Fuel Oil Chemistry and One-Time Inspection programs.

The staff reviewed LRA Section 3.3.2.2.12, item 1 against the criteria described in SRP-LR Section 3.3.2.2.12, item 1, which state that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The SRP-LR also states that the AMP relies on monitoring and control of fuel oil contamination to mitigate degradation. The SRP-LR further states that a one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or progressing very slowly such that the component's intended function will be maintained during the period of extended operation. The GALL Report, under items VII.H1-1, VII.H1-3, and VII.H1-6, recommends managing the aging effect using the Fuel Oil Chemistry Program augmented by the One-Time Inspection Program to verify the effectiveness of the fuel oil chemistry control.

The staff reviewed the applicant's Fuel Oil Chemistry and the One-Time Inspection programs, which are evaluated in SER Sections 3.0.3.2.8 and 3.0.3.1.11, respectively. The applicant stated that the One-Time Inspection Program includes: (1) determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience; (2) identification of inspection locations based on the aging effect; (3) selection of the examination technique with acceptance criteria; and (4) evaluation of the results including the need for additional inspections or other corrective actions. The staff finds the credited programs acceptable to manage aging for these components because: (1) the Fuel Oil Chemistry Program will assure that contaminates are maintained at acceptable levels in fuel oil and identify the actions required if the fuel oil contaminates exceed limits, and (2) the One-Time Inspection Program will include a one-time inspection of selected components at appropriate locations (e.g., low or stagnant flow areas) to verify the effectiveness of the Fuel Oil Chemistry Program for managing the effects of aging due to the potential corrosion mechanisms.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12, item 1 criteria. For those items that apply to LRA Section 3.3.2.2.12, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function 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 3.3.2.2.12.2, referenced by LRA Table 3.3.1, item 3.3.1-33, addresses stainless steel piping, piping components, and piping elements exposed to lubricating oil which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil for the component cooling, EDGs and auxiliaries, reactor coolant, and service water systems.

The staff reviewed LRA Section 3.3.2.2.12.2 against the criteria in SRP-LR Section 3.3.2.2.12, item 2, which state that loss of material due to pitting, crevice, and microbiologically-influenced corrosion could occur in stainless steel piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil analysis program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.3.1-33, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (1) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (2) the applicant stated that the One-Time Inspection Program will be used to examine stainless steel piping, piping components, piping elements, and heat exchanger components to verify the effectiveness of the Lubricating Oil Analysis

Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.12, item 2 and, therefore, the applicant's AMR is consistent with GALL Report items VII.C1-14, VII.C2-12, VII.E1-15, VII.E4-12, VII.G-18, and VII.H2-17.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12 criteria. For the line items that apply to LRA Sections 3.3.2.2.12.1 and 3.3.2.2.12.2, 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).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12 criteria. For those line items that apply to LRA Section 3.3.2.2.12, 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).

3.3.2.2.13 Loss of Material Due to Wear

LRA Section 3.3.2.2.13 refers to Table 3.3.1, item 3.3.1-34 and addresses elastomer components that are subject to wear in the applicant's auxiliary systems. The applicant stated that elastomer components determined to be subject to wear, based on plant operating experience, are periodically replaced and are not subject to an AMR. The applicant further stated that elastomer components that are not periodically replaced are evaluated for hardening and loss of strength due to elastomer degradation in LRA Table 3.3.1, item 3.3.1-11 and are included in the Periodic Inspection Program.

The staff reviewed LRA Section 3.3.2.2.13 against the criteria in SRP-LR Section 3.3.2.2.13, which state that loss of material due to wear can occur in elastomer seals and components exposed to uncontrolled indoor air. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

The staff noted that the applicant invokes periodic replacement of elastomer components subject to wear as its basis for not subjecting the components to an AMR. The staff further noted that this basis is consistent with the requirements of 10 CFR 54.21(a)(ii). However, the staff did not find sufficient information in the LRA to confirm that the frequency of the applicant's component replacement is adequate. By letter dated July 23, 2010, the staff issued RAI 3.3.2.2.13-01 requesting that the applicant: (1) identify what systems contain in-scope elastomer components that are subject wear and periodically replaced and (2) provide the basis for determining the replacement frequency of those components.

In its response dated August 10, 2010, the applicant stated that the only in-scope elastomer components that experience wear and are subject to periodic replacement are fire hoses. The applicant also stated that fire hoses are subject to relative motion when installed on hose reels or hose racks, or when deployed for use or testing. The applicant further stated that as per LRA Section 2.1.6.4, fire hoses are considered to be a consumable item whose replacement frequency is based on NFPA testing and inspection standards that are implemented by controlled station procedures.

The staff notes that although the replacement frequency for the fire hoses is based on testing and inspection, this testing and inspection is controlled by plant procedures based on NFPA standards and the use of NFPA standards is consistent both with standard industry practice and with recommendations in GALL AMP XI.M27, "Fire Water System." The staff finds the applicant's response acceptable because the in-scope fire hoses that are subject to wear are appropriately evaluated as not being long-lived, passive items and thus are screened out from aging management. The staff's concern described in RAI 3.3.2.2.13-01 is resolved.

Based upon the applicant's periodic replacement of elastomer components subject to wear, the staff finds that an AMR of these components is not required and finds it acceptable for the applicant to designate AMR results in Table 3.3.1, item 3.3.1-34 as not applicable.

3.3.2.2.14 Loss of Material Due to Cladding Breach

LRA Section 3.3.2.2.14, referenced by Table 3.3.1, item 3.3.1-35, addresses steel charging pump casings with stainless steel cladding exposed to treated borated water which are being managed for loss of material due to cladding breach by the One-Time Inspection Program for Unit 2. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is only applicable to Unit 2 because the Unit 1 charging pumps have been changed to all stainless steel pump casings following the inspections in 1997 and 1998. The applicant further stated that the Unit 2 pumps are also included with item 3.3.1-91, which is being managed by the Water Chemistry Program, and that the effectiveness of the Water Chemistry Program will be verified by the One-Time Inspection Program.

The staff reviewed LRA Section 3.3.2.2.14 against the criteria described in SRP-LR Section 3.3.2.2.14, which state that loss of material due to cladding breach could occur for steel charging pump casings with stainless steel cladding exposed to treated borated water. The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed and that the acceptance criteria are described in Branch Technical Position RLSB-1.

The staff's evaluation of the applicant's One-Time Inspection Program is documented in SER Section 3.0.3.1.11. The staff notes that the applicant's One-Time Inspection Program includes determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience, and the identification of inspection locations is based on the aging effect. In its review of components associated with item 3.3.1-35, the staff finds the applicant's proposal to manage aging using the above program acceptable because the One-Time Inspection Program will verify that unacceptable degradation is not occurring.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.14 criteria. For those items that apply to LRA Section 3.3.2.2.14, the staff determines that the LRA is consistent with the GALL Report and 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).

3.3.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.3.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1 through 3.3.2-26, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-26, the applicant indicated, via generic notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line 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 line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

LRA Table 3.3.2-14 was revised as a result of the response to RAI B.2.1.9-01, dated July 8, 2010. The revision added AMR items in these tables to reference the applicant's Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff notes that the Bolting Integrity Program is supplemented by other AMPs, including but not limited to the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection programs. These other AMPs supplement the Bolting Integrity Program by implementing the requirements of the Bolting Integrity Program for pressure-retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action accurately adds the related line items to reference the Bolting Integrity Program; however, the technical evaluations documented in the SER do not change since the management of the aging effect will still be implemented by the AMP identified in conjunction with the Bolting Integrity Program.

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 had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.3.2.3.1 Auxiliary Systems – Auxiliary Building Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-1

The staff reviewed LRA Table 3.3.2-1, which summarizes the results of AMR evaluations for the auxiliary building ventilation system component groups.

In LRA Tables 3.3.2-1, 3.3.2-3, 3.3.2-6, 3.3.2-8, 3.3.2-15, 3.3.2-19, 3.3.2-22, 3.3.2-26, and 3.1.2-1, the applicant stated that for glass filter housings, sight glasses, flow elements, and tanks (sampling vessels and accumulators) exposed to air with borated water leakage, wetted air or gas, and closed-cycle cooling water, there is no aging effect and no AMP is proposed.

The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for these components and material.

The staff reviewed all AMR result line items in the GALL Report where the material is glass and confirms that for this environment, there are no entries in the GALL Report for this component and material.

The staff finds the applicant's proposal acceptable because, as supported by various GALL Report line items such as EP-15, EP-29, and EP-30, there are no known aging effects for glass exposed to any water environment of nuclear power plants.

In LRA Tables 3.3.2-1, 3.3.2-7, 3.3.2-15, and 3.3.2-26, the applicant stated that elastomer door seals and flexible connections exposed to air with treated borated water leakage has no AERM and that for this component, material, and environment combination, no AMP is needed. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR results in the GALL Report where the component type is elastomer door seals or flexible connections and confirms that there are no entries for this component and material combination where the environment is wetted air or gas, or similar.

The staff notes that the LRA does not provide sufficient information to evaluate the effect of the air with borated water leakage and to wetted air or gas environments for components in this system because the LRA does not explain how these components are exposed to these environments. By letter dated June 11, 2010, the staff issued RAI 3.3.2-02 requesting that the applicant provide sufficient information for the staff to evaluate the effect of these environments for components in these systems.

In its response dated July 8, 2010, the applicant stated that all components in the auxiliary building (including the inner penetration area), containment structure, and fuel handling building, two external environments are applied: indoor air and air with borated water leakage. The applicant also stated that probability of an elastomer being exposed to borated water in these locations is extremely small, but the environment was included for completeness. The applicant further stated that ventilation components are assigned an environment of wetted air or gas unless the air is processed through filters or driers to remove moisture and contaminants.

The staff finds the applicant's response acceptable because it clarified the exposure mechanism and potential, allowing the staff to evaluate individual AMR line items. The staff's concern described in RAI 3.3.2-02 is resolved.

The staff noted a potential discrepancy between the applicant's AMR results for elastomer door seals and flexible connections exposed to wetted air or gas (internal) and the results for elastomer door seals and flexible connections exposed to air with treated borated water leakage. By letter dated June 11, 2010, the staff issued RAI 3.3.2-01 requesting that the applicant: (1) provide a basis for its statement that there is no aging effect for elastomer door seals and flexible connections exposed to air with borated water leakage, and (2) explain why elastomer door seals and flexible connections exposed to wetted air or gas would exhibit an aging effect and similar components exposed to air with treated borated water leakage would not.

In its response dated July 8, 2010, the applicant stated that two external environments are applied to all components in the auxiliary building (including the inner penetration area), containment structure, and fuel handling building: indoor air and air with borated water leakage. The air with borated water leakage is included specifically to cover metallic component types whose external surfaces are susceptible to boric acid wastage. The applicant also stated that for elastomeric components located in these areas, the AMR line items where elastomers are exposed to air with borated water leakage, the intent was to state that there are no additional AERMs than for the same materials in the AMR line items exposed to an indoor air environment.

The staff finds the applicant's response and proposal that there are no additional AERMs and that for this component, material, and environment combination, no additional AMP is needed acceptable because the aging effects of hardening and loss of strength due to elastomer degradation as a result of being exposed to either indoor air or air with borated water leakage environment will be effectively managed by the Periodic Inspection Program, which includes visual inspections and physical manipulations to detect degradation. The staff's concern described in RAI 3.3.2-01 is resolved.

In LRA Tables 3.3.2-1, 3.3.2-7, 3.3.2-8, 3.3.2-15, and 3.3.2-26, the applicant stated that elastomer door seals and flexible connections exposed to wetted air or gas (internal) has an aging effect of hardening and loss of strength due to elastomer degradation that will be managed by the Periodic Inspection Program. The AMR line items cited generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR results in the GALL Report where the component type is elastomer door seals or flexible connections and confirmed that there are no entries for this component and material combination where the environment is wetted air or gas, or similar. This review confirms that the applicant's use of generic note G is acceptable.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. In its review of the Periodic Inspection Program, the staff noted that it is a plant-specific program that proposes to detect the aging of elastomer door seals and flexible connections through the use of visual inspections and physical manipulations. The staff finds the applicant's proposal to manage aging of elastomer door seals and flexible connections exposed to wetted air or gas (internal) using the Periodic Inspection Program acceptable because: (1) the program performs visual inspections and physical manipulations that are capable of detecting hardening and loss of strength in elastomer components; and (2) the program initiates corrective actions, implemented through the applicant's corrective action program, if indications of age-related degradation are found.

In LRA Table 3.3.2-1, the applicant stated that polymer piping and fittings exposed to air-indoor (external), air with borated water leakage (external), or wetted air or gas (internal) have no AERM and that for this component, material, and environment combination, no AMP is needed. The AMR line items cite generic note F, indicating that the material is not in the GALL Report for this component.

The staff reviewed all material entries in the GALL Report and confirmed that polymer material is not included in the GALL Report. This review confirms that the applicant's use of generic note F is acceptable.

For these AMR results, the applicant also cited plant-specific note 5, stating that polymer (plexiglass) material located indoors and subject to an indoor air, wetted air or gas, or air with borated water leakage is not subject to significant aging effects. The applicant further stated that polymer materials do not experience aging effects unless exposed to temperatures, radiation, or chemicals capable of attacking the specific polymer chemical composition and that polymer materials selected for compatibility with the environment during the design will not experience significant degradation.

Based on its review of technical literature (including, Roff, W.J., *Fibres, Plastics, and Rubbers: A Handbook of Common Polymers*) and current industry research and operating experience related to plexiglass and related polymer piping and piping components, the staff determines that, in the absence of specific environmental stressors such as ultraviolet light, high radiation, or ozone concentrations, piping components made of these materials do not exhibit aging effects of concern during the period of extended operation. The staff determines that for plexiglass and related polymer piping and piping components in a plant indoor air, air with boron leakage, or wetted environment, there are no aging effects that cause degradation of the components during the period of extended operation. On the basis that the subject components have no aging effects that cause degradation during the period of extended operation, the staff finds the applicant's AMR results for these components, indicating that there is no AERM and no AMP is needed, to be acceptable.

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).

3.3.2.3.2 Auxiliary Systems – Chemical and Volume Control System – Summary of Aging Management Evaluation – LRA Table 3.3.2-2

The staff reviewed LRA Table 3.3.2-2, which summarizes the results of AMR evaluations for the chemical and volume control system component groups.

In LRA Tables 3.3.2-2 and 3.4.2-1, the applicant stated that stainless steel tanks exposed externally to soil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Aboveground Non-Steel Tanks Program. The AMR line items cite generic note G.

The staff reviewed the applicant's Aboveground Non-Steel Tanks Program and its evaluation is documented in SER Section 3.0.3.3.3. The staff finds the applicant's program acceptable to manage aging for these components because it includes visual inspections of the accessible outer surfaces of the tank, down to the concrete foundation, and thickness measurements of the tank bottom from inside of the tank to determine if there is any loss of material occurring where the exterior of the tank bottom is in contact with the soil.

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 Auxiliary Systems – Chilled Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-3

The staff reviewed LRA Table 3.3.2-3, which summarizes the results of AMR evaluations for the chilled water system component groups.

In LRA Tables 3.3.2-3 and 3.3.2-23, the applicant stated that copper alloy heat exchanger components exposed to wetted air and gas are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR line items in the GALL Report where the material is copper alloy and the aging effect is reduction of heat transfer and confirms that for this environment, there are no entries in the GALL Report for this component and material.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff finds the monitoring program acceptable because it uses visual inspections which are appropriate to determine whether there is any loss of component function caused by reduction of heat transfer due to fouling. The visual inspections are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.4 Auxiliary Systems – Circulating Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-4

The staff reviewed LRA Table 3.3.2-4, which summarizes the results of AMR evaluations for the circulating water system component groups.

In LRA Tables 3.3.2-4, 3.3.2-6, 3.3.2-10, 3.3.2-12, 3.3.2-18, and 3.3.2-23, the applicant stated that carbon and low-alloy steel bolting exposed to groundwater and soil is being managed for loss of preload due to thermal effects, gasket creep, and self-loosening and loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion by the Bolting Integrity Program. The applicant also stated that it plans to conduct inspections in accordance with the frequency outlined in the Buried Piping Inspection Program.

The staff reviewed the applicant's Bolting Integrity and Buried Piping Inspection programs and its evaluations are documented in SER Sections 3.0.3.2.2 and 3.0.3.2.10, respectively. The staff noted that the Bolting Integrity Program manages loss of material and loss of preload by performing visual inspections. The staff also noted that the Buried Piping Inspection Program inspection frequency is based upon the preventive measures established in the program, which include maintaining external coatings and wrappings. It is unclear to the staff if external coatings and wrappings are used on the carbon and low-alloy steel bolting. By letter dated May 24, 2010, the staff issued RAI 3.3.2.3.4-1 requesting that the applicant indicate if coatings are used on this bolting and how those coatings are maintained. Secondly, the staff asked the applicant if coatings are not used, why is the frequency associated with the Buried Piping

Inspection Program an acceptable level of monitoring when that program expects coatings to be used as a preventive measure.

In its response dated June 14, 2010, the applicant stated that station documentation and site interviews indicate that buried bolting was initially coated, but that buried carbon steel bolts in the fire protection system have been observed without coatings and that it does not take credit for coatings to prevent loss of intended function. The applicant also stated that buried bolting in the service water system is designated as Class 3 and is inspected in accordance with ASME Code Section XI, IWD-2500 and IWD-5000, 1998 Edition with 2000 Addenda, which allows use of a flow test to confirm no significant leakage in lieu of visual inspections. The applicant further stated that non-ASME buried bolts will be opportunistically inspected in accordance with the Buried Piping Inspection Program. The staff notes that ASME Code Section XI, Subsection IWA-5244, “Buried Components,” indicates that for buried components where a VT-2 visual examination cannot be performed, the examination requirement is satisfied by conducting a pressure loss test or a flow test. The staff finds the applicant’s response to RAI 3.3.2.3.4-1 and its proposal to manage aging for bolting exposed to soil using the Bolting Integrity and Buried Piping Inspection programs acceptable because the buried bolts will be inspected using either system flow tests or opportunistic inspections, which is consistent with the GALL Report recommendations that periodic inspections be conducted. The staff’s concern described in RAI 3.3.2.3.4-1 is resolved.

In LRA Tables 3.3.2-4 and 3.3.2-23, for component type piping and fittings, the applicant proposed to assign reinforced concrete to the Open-Cycle Cooling Water System Program to manage the aging effects of cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel, increase in porosity and permeability, and aggressive chemical attack in a raw water (internal) groundwater/soil environment. This item references generic note J or note F (depending on the table). The applicant stated that these components have the intended function of pressure boundary and are examined using the Open-Cycle Cooling Water System Program. The staff’s review of the applicant’s Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9.

The staff notes that the applicant’s Open-Cycle Cooling Water System Program includes activities to manage internal degradation of piping, including cracking, loss of material, and increase in porosity and permeability. The staff also notes that the concrete piping within scope of this program has a polymer coating applied to the interior surface of the pipe and the interior of each piping header is visually inspected every other refueling outage for signs of coating and concrete degradation. Visual inspections of the piping header will detect indications of age-related degradation in the piping and the header condition should be representative of the main piping. The type and frequency of the inspections are appropriate based on guidance provided by other GALL Report programs which manage aging of concrete, such as the Structures Monitoring Program. These programs suggest visual inspections with a frequency of at least every 5 years to detect degradation of concrete exposed to raw water. Based on its review, the staff finds that the applicant addressed the AERM adequately.

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 Auxiliary Systems – Component Cooling System – Summary of Aging Management Evaluation – LRA Table 3.3.2-5

The staff reviewed LRA Table 3.3.2-5, which summarizes the results of AMR evaluations for the component cooling system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.6 Auxiliary Systems – Compressed Air System – Summary of Aging Management Evaluation – LRA Table 3.3.2-6

The staff reviewed LRA Table 3.3.2-6, which summarizes the results of AMR evaluations for the compressed air system component groups.

The staff's evaluation for carbon and low-alloy steel bolting exposed to groundwater and soil, which are being managed for loss of preload and loss of material by the Bolting Integrity Program, is documented in SER Section 3.3.2.3.4.

In LRA Tables 3.3.2-6 and 3.3.2-23, the applicant stated that stainless steel heat exchanger components exposed to wetted air or gas are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program. The AMR line items cite generic note H. The AMR line items also cite plant-specific note 6, indicating that the Periodic Inspection Program is being applied to confirm that the internal environment remains sufficiently dry in order to preclude the effects of aging.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff finds the applicant's program acceptable to manage aging for these components because stainless steel components exposed to dry air experience no aging effects and the program includes visual inspections which can detect reduction of heat transfer due to fouling and which will confirm that the wetted air or gas environment remains dry enough such that aging does not occur.

In LRA Table 3.3.2-6, the applicant stated that aluminum heat exchanger components for the SBO aftercooler externally exposed to indoor air or internally exposed to wetted air and gas are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program. The AMR line items cite generic note H for this item, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirms that the applicant has identified the correct aging effects for this component, material, and environment combination because the GALL Report states that reduction of heat transfer results from fouling on heat transfer surfaces and that particulate fouling can be due to dust and corrosion products. The staff notes that the aluminum heat exchanger surfaces will be susceptible to this aging effect. The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff finds the applicant's proposal to manage aging using the above program acceptable because the Periodic Inspection Program uses visual inspections, which are capable of detecting dust and corrosion products on the aluminum heat exchanger surfaces to manage reduction of heat transfer due to fouling.

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 Auxiliary Systems – Containment Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-7

The staff reviewed LRA Table 3.3.2-7, which summarizes the results of AMR evaluations for the containment ventilation system component groups.

The staff's evaluation of elastomer door seals and flexible connections exposed to wetted air or gas (internal) having an aging effect of hardening and loss of strength due to elastomer degradation that will be managed by the Periodic Inspection Program with generic note G is documented in SER Section 3.3.2.3.1.

The staff's evaluation of elastomer door seals and flexible connections exposed to air with treated borated water leakage for which the applicant cited generic note G is documented in SER Section 3.3.2.3.1.

3.3.2.3.8 Auxiliary Systems – Control Area Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-8

The staff reviewed LRA Table 3.3.2-8, which summarizes the results of AMR evaluations for the control area ventilation system component groups.

The staff's evaluation of elastomer door seals and flexible connections exposed to wetted air or gas (internal) having an aging effect of hardening and loss of strength due to elastomer degradation that will be managed by the Periodic Inspection Program with generic note G is documented in SER Section 3.3.2.3.1.

3.3.2.3.9 Auxiliary Systems – Cranes and Hoists – Summary of Aging Management Evaluation – LRA Table 3.3.2-9

The staff reviewed LRA Table 3.3.2-9, which summarizes the results of AMR evaluations for the cranes and hoists system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.10 Auxiliary Systems – Demineralized Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-10

The staff reviewed LRA Table 3.3.2-10, which summarizes the results of AMRs for the demineralized water system component groups.

The staff's evaluation for carbon and low-alloy steel bolting exposed to groundwater and soil, which are being managed for loss of preload and loss of material by the Bolting Integrity Program, is documented in SER Section 3.3.2.3.4.

In LRA Table 3.3.2-10, the applicant stated that aluminum storage tanks for demineralized water exposed to soil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Aboveground Non-Steel Tanks Program. The AMR line item cites generic note G for this item, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, as noted in NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," steel in this environment is susceptible to the above notes aging mechanisms and aluminum will be similarly affected. The staff's evaluation of the applicant's Aboveground Non-Steel Tanks Program is documented in SER Section 3.0.3.3.3. The staff finds the applicant's proposal to manage aging using the above program acceptable because the Aboveground Non-Steel Tanks Program uses visual inspection and UT, which are able to detect loss of material due to pitting, crevice, and microbiologically-influenced corrosion.

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 Auxiliary Systems – Emergency Diesel Generators and Auxiliary System – Summary of Aging Management Evaluation – LRA Table 3.3.2-11

The staff reviewed LRA Table 3.3.2-11, which summarizes the results of AMR evaluations for the EDGs and auxiliary system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.12 Auxiliary Systems – Fire Protection System – Summary of Aging Management Evaluation – 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 system component groups.

In LRA Table 3.3.2-12, the applicant stated that grout fire barriers (penetration seals) exposed externally to indoor uncontrolled air and outdoor air are being managed for cracking due to shrinkage and freeze-thaw and loss of material due to spalling and scaling by the Fire Protection and Structures Monitoring programs. The AMR line items cite generic note F. The AMR line items also cite plant-specific note 5, indicating that, based on industry standards and guidelines, grout is susceptible to cracking due to shrinkage in this environment. The AMR line items further cite plant-specific note 6, indicating that grout is susceptible to loss of material due to spalling and scaling and cracking due to freeze-thaw in an outdoor air environment, consistent with industry guidance.

The staff reviewed the applicant's Fire Protection and Structures Monitoring programs and its evaluations are documented in SER Sections 3.0.3.2.5 and 3.0.3.2.15, respectively. The staff notes that the Fire Protection Program is used for other fire barriers such as penetration seals, walls, floors, and ceilings and that grout material is regularly used as a penetration seal to provide a fire barrier. The staff also notes that the applicant's Fire Protection Program provides for visual inspections of fire barriers once every 18 months for detection of cracking and loss of material and that since these materials serve the intended function of a fire barrier, the Fire Protection Program is an appropriate program to manage cracking and loss of material for these components. The staff further notes that the applicant's Structures Monitoring Program provides for periodic visual inspection of cracking and loss of material of concrete structures and penetrations at a frequency not to exceed 5 years and that since grout is similar in nature to concrete, the Structures Monitoring Program is an appropriate program to manage cracking and loss of material for grout.

The staff finds the applicant's currently proposed programs acceptable to manage loss of material and cracking for these components because: (1) for this material in an environment of indoor uncontrolled and outdoor air, the aging effects are expected to be cracking due to shrinkage and freeze-thaw and loss of material due to spalling and scaling; and (2) the periodic visual inspections performed by the Fire Protection and Structures Monitoring programs will confirm that there is no loss of material or cracking, or will result in a corrective action to assess the situation.

In LRA Table 3.3.2-12, the applicant stated that asbestos fire barriers (walls, ceiling, and floors) exposed to indoor air have no aging effects and no AMP is proposed. The AMR line item cites generic note J. The AMR line item also cites plant-specific note 14, which states:

> Asbestos is a mineral fiber encased in an inorganic binder. The asbestos material is located in an air-indoor environment and is not subject to significant aging effects. Asbestos materials do not experience aging effects unless exposed to temperatures, radiation, or chemical capable of attacking the specific inorganic chemical composition. Asbestos materials are selected for compatibility with the environment during the design.
>
> Asbestos material in this non-aggressive air environment is not expected to experience significant aging effects. This is consistent with plant operating experience.

The staff finds the applicant's proposal acceptable because the staff acknowledges that the use of asbestos as a fire barrier on walls, ceilings, and floors in power plant environments is a design-driven criterion and, once selected for the environment, will not have any significant age-related degradation. On the basis that the asbestos is not located in areas of high temperatures or radiation, the staff finds that the asbestos fire barrier will not have any AERMs in an indoor air environment.

In LRA Table 3.3.2-12, the applicant stated that fiberglass cloth fire barrier wraps exposed to indoor air and air with borated water leakage have no aging effect and no AMP is proposed. The AMR line items cite generic note J. The AMR line items also cite plant-specific note 15, which states:

> Fiberglass cloth consists of inorganic fibers encased [in] a polymeric binder. The polymer material located in air-indoor or air with borated water leakage environment is not subject to significant aging effects. Polymer materials do not experience aging effects unless exposed to temperatures, radiation, or chemical capable of attacking the specific polymer chemical composition. Polymer materials are selected for compatibility with the environment during the design. Polymer material in these non-aggressive air environments is not expected to experience significant aging effects. This is consistent with plant operating experience.

The staff finds the applicant's proposal acceptable because the staff acknowledges that the use of fiberglass in power plant environments is a design-driven criterion and, once selected for the environment, will not have any significant age-related degradation. On the basis that the fiberglass cloth fire barrier wrap is not located in areas of high temperatures or radiation, the staff finds that the fiberglass cloth fire barrier wrap will not have any AERMs in indoor air or air with borated water leakage environments.

In LRA Table 3.3.2-12, the applicant stated that copper alloy valve body components exposed to outdoor air are being managed for loss of material by the Fire Protection Program. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for these components and material.

The staff reviewed all AMR result line items in the GALL Report where the material is copper alloy and the aging effect/mechanism is loss of material and confirmed that for this environment, there are no entries in the GALL Report for this component and material.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.5. The staff finds the monitoring program acceptable because it uses visual inspections which are appropriate to determine whether there is any loss of component function caused by loss of material due to exposure to an outdoor air environment. The visual inspections are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

In LRA Table 3.3.2-12, the applicant stated that copper alloy (greater than 15 percent Zn) sprinkler head components exposed to outdoor air are being managed for loss of material by the Fire Water System Program. The AMR line item cites generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR result line items in the GALL Report where the material is copper alloy (greater than 15 percent Zn) and the aging effect/mechanism is loss of material and confirmed that for this environment, there are no entries in the GALL Report for this component and material.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.6. The staff finds the monitoring program acceptable to manage aging for these components because it includes fire water system functional testing, flow tests, flushes, and testing of sprinkler heads or replacement every 50 years based on NFPA-25 codes, which are appropriate to determine whether there is any loss of component function caused by loss of material due to exposure to an outdoor air environment. The visual inspections are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

The staff's evaluation for carbon and low-alloy steel bolting exposed to groundwater and soil, which are being managed for loss of preload and loss of material by the Bolting Integrity Program, is documented in SER Section 3.3.2.3.4.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.13 Auxiliary Systems – Fresh Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-13

The staff reviewed LRA Table 3.3.2-13, which summarizes the results of AMR evaluations for the fresh water system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.14 Auxiliary Systems – Fuel Handling and Fuel Storage System – Summary of Aging Management Evaluation – LRA Table 3.3.2-14

The staff reviewed LRA Table 3.3.2-14, which summarizes the results of AMR evaluations for the fuel handling and fuel storage system component groups.

In LRA Table 3.3.2-14, the applicant stated that for new fuel storage racks made of treated wood externally exposed to indoor air, there are no AERMs. The applicant referenced generic note F for this item, indicating that this material is not in the GALL Report for this component. In plant-specific note 4, the applicant further stated that wood components that are protected from a weather environment are not susceptible to loss of material or change in material properties (such as rot) unless the wood is in a moist location or exposed to sustained high temperatures. The applicant indicated that the new fuel storage racks in the fuel handling building are not subjected to any of these conditions that would lead to aging effects. Therefore, the applicant did not assign an AMP for this component material and environment combination.

The staff evaluated the applicant's claim that there are no AERMs for this component, material, and environment combination and noted that the GALL Report does not describe the aging effects for wood. The staff also reviewed the available literature and determined that: (1) by definition, treated wood is “wood that has been pressure treated with a preservative to improve the resistance of wood to destruction from fungi, insects and marine borers” (See *Wood Handbook: Wood as an Engineering Material*, Gen. Tech. Rep. FPL-GTR-113, U.S. Department of Agriculture, Forest Service, Forest Products Laboratory, 1999); and (2) aging of wood can be curtailed if its exposure to heat and moisture are minimized or eliminated (See “Microbial Degradation of Wood,” by R. I. Morris, in *Uhlig’s Corrosion Handbook*, 2nd Edition, Edited by R. R. Winston, John Wiley & Sons, 2000). Based on its review of the LRA and available literature regarding the aging of wood, the staff finds the applicant’s management of the wood storage racks acceptable because the wood product is specially treated against the effects of rot and the indoor air plant environment is not conducive to biotic degradation.

In LRA Table 3.3.2-14, the applicant stated that new polymer fuel storage rack components exposed to indoor air or air with borated water leakage (external) have no AERM and that for this component, material, and environment combination, no AMP is needed. The AMR line items cite generic note F, indicating that the material is not in the GALL Report for this component.

The staff reviewed all material entries in the GALL Report and confirmed that polymer material is not included in the GALL Report.

For these AMR results, the applicant also cited plant-specific note 8, stating that polymer materials located indoors and subject to an indoor air or air with borated water leakage environment is not subject to significant aging effects. The applicant further stated that polymer materials are located in non-aggressive environments, but that aging effects could occur if exposed to temperature, radiation, or chemicals capable of attacking the specific polymer chemical composition. The applicant further stated that during design, these polymer materials are selected for compatibility so degradation in these environments is not expected to occur.

Based on its review of technical literature (e.g., Roff, W.J., *Fibres, Plastics, and Rubbers: A Handbook of Common Polymers*, Academic Press Inc., New York, 1956) and current industry research and operating experience related to polymer structural components, the staff has determined that, in the absence of specific environmental stressors such as ultraviolet light, high radiation, or ozone concentrations, structural components made of these materials do not exhibit aging effects of concern during the period of extended operation. The staff noted that new reactor fuel does not emit radiation appreciably above background and is not expected to create a radiation-related environmental stressor for new fuel storage racks. The staff has determined that for appropriately selected polymer structural components in a plant indoor air or air with boron leakage environment, there are no aging effects that cause degradation of the components during the period of extended operation. On the basis that the subject components have no aging effects that cause degradation during the period of extended operation, the staff finds the applicant’s AMR results for these components, indicating that there is no AERM and no AMP is needed, to be acceptable.

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 Auxiliary Systems – Fuel Handling Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-15

The staff reviewed LRA Table 3.3.2-15, which summarizes the results of AMR evaluations for the fuel handling ventilation system component groups.

The staff's evaluation of elastomer door seals and flexible connections exposed to wetted air or gas (internal) having an aging effect of hardening and loss of strength due to elastomer degradation that will be managed by the Periodic Inspection Program with generic note G is documented in SER Section 3.3.2.3.1.

The staff's evaluation of elastomer door seals and flexible connections exposed to air with treated borated water leakage for which the applicant cited generic note G is documented in SER Section 3.3.2.3.1.

3.3.2.3.16 Auxiliary Systems – Fuel Oil System – Summary of Aging Management Evaluation – LRA Table 3.3.2-16

The staff reviewed LRA Table 3.3.2-16, which summarizes the results of AMR evaluations for the fuel oil system component groups.

In LRA Table 3.3.2-16, the applicant stated that for polymer sight glasses exposed to fuel oil and indoor air, there is no aging effect and no AMP is proposed. The AMR line items cite generic note F, indicating that the material is not in the GALL Report for this component.

The staff reviewed all AMR result line items in the GALL Report where the environments are fuel and indoor air and confirmed that there are no entries for this component or material.

The staff notes that these line items are located in the fuel oil system and as such, would not be expected to be exposed to high radiation or ozone concentrations. The staff finds the applicant's proposal acceptable because based on its review of technical literature (e.g., Roff, W.J., *Fibres, Plastics, and Rubbers: A Handbook of Common Polymers*, Academic Press Inc., New York, 1956) and current industry research and operating experience related to plexiglass, the staff has determined that, in the absence of specific environmental stressors such as ultraviolet light, high radiation, or ozone concentrations, components made of these materials do not exhibit aging effects of concern during the period of extended operation. The staff determines that for polymer sight glasses in a plant indoor air environment or exposed to fuel oil, there are no aging effects that cause degradation of the components during the period of extended operation. On the basis that the subject components have no aging effects that cause degradation during the period of extended operation, the staff finds the applicant's AMR results for these components, indicating that there is no AERM and no AMP is needed, to be acceptable.

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 Auxiliary Systems – Heating Water and Heating Steam System – Summary of Aging Management Evaluation – LRA Table 3.3.2-17

The staff reviewed LRA Table 3.3.2-17, which summarizes the results of AMR evaluations for the heating water and heating steam system component groups.

In LRA Table 3.3.2-17, the applicant stated that the carbon steel piping, fittings, and valves exposed internally to closed-cycle cooling water are being managed for wall thinning due to flow-accelerated corrosion by the Flow-Accelerated Corrosion Program. The AMR line items cite generic note H. The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, as stated in EPRI TR-106611, "Flow-Accelerated Corrosion in Power Plants," wall thinning can occur in demineralized or neutral water with low oxygen content, where there is flowing water or wet steam in carbon steel components with a temperature range from 88 °C to 260 °C (190 °F to 500 °F). In addition, the staff noted that the loss of material due to other mechanisms for these components is addressed in other LRA line items through other AMPs.

The staff's evaluation of the applicant's Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.2.1. Although the applicant cited generic note H to indicate that this aging effect was not included in the GALL Report for this component, material, and environment combination, the staff noted several items including item 3.4.1-29, which addresses wall thinning due to flow-accelerated corrosion for comparable components in steam or treated water environments. The staff also notes that the heating water and heating steam system will be enhanced prior to the period of extended operation to institute a pure water control program in accordance with EPRI guidance, which will ensure environmental conditions comparable to other treated water systems. The staff finds the applicant's proposal to manage aging using the Flow-Accelerated Corrosion Program acceptable because the GALL Report recommends this AMP to manage the same aging effect for the combination of comparable components, materials, and environment.

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 Auxiliary Systems – Non-radioactive Drain System – Summary of Aging Management Evaluation – LRA Table 3.3.2–18

The staff reviewed LRA Table 3.3.2–18, which summarizes the results of AMRs for the non-radioactive drain system component groups.

In LRA Table 3.3.2-18, the applicant stated that copper alloy valve body components exposed to outdoor air are being managed for loss of material by the Periodic Inspection Program. The AMR line item cites generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR result line items in the GALL Report where the material is copper alloy and the aging effect/mechanism is loss of material and confirmed that for this environment, there are no entries in the GALL Report for this component and material.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff finds the monitoring program acceptable because it uses visual inspections which are appropriate to determine whether there is any loss of component function caused by loss of material due to exposure to an outdoor air environment. The visual inspections are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

The staff's evaluation for carbon and low-alloy steel bolting exposed to groundwater and soil, which are being managed for loss of preload and loss of material by the Bolting Integrity Program, is documented in SER Section 3.3.2.3.4.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.19 Auxiliary Systems – Radiation Monitoring System – Summary of Aging Management Evaluation – LRA Table 3.3.2-19

The staff reviewed LRA Table 3.3.2-19, which summarizes the results of AMR evaluations for the radiation monitoring system component groups.

The staff's evaluation for glass filter housings, sight glasses, flow elements, and tanks (sampling vessels and accumulators) exposed to air with borated water leakage, wetted air or gas, and closed-cycle cooling water, for which no aging effect and no AMP is proposed, is documented in SER Section 3.3.2.3.1.

3.3.2.3.20 Auxiliary Systems – Radioactive Drain System – Summary of Aging Management Evaluation – LRA Table 3.3.2-20

The staff reviewed LRA Table 3.3.2-20, which summarizes the results of AMR evaluations for the radioactive drain system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.21 Auxiliary Systems – Radwaste System – Summary of Aging Management Evaluation – LRA Table 3.3.2-21

The staff reviewed LRA Table 3.3.2-21, which summarizes the results of AMR evaluations for the radwaste system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.22 Auxiliary Systems – Sampling System – Summary of Aging Management Evaluation – LRA Table 3.3.2-22

The staff reviewed LRA Table 3.3.2-22, which summarizes the results of AMR evaluations for the sampling system component groups.

The staff's evaluation for glass filter housings, sight glasses, flow elements, and tanks (sampling vessels and accumulators) exposed to air with borated water leakage, wetted air or gas, and closed-cycle cooling water, for which no aging effect and no AMP is proposed, is documented in SER Section 3.3.2.3.1.

3.3.2.3.23 Auxiliary Systems – Service Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-23

The staff reviewed LRA Table 3.3.2-23, which summarizes the results of AMR evaluations for the service water system component groups.

In LRA Table 3.3.2-23, the applicant stated that the nickel-alloy hoses exposed to raw water are being managed for fouling and loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Open-Cycle Cooling Water System Program. The AMR line item cites generic note H. This line item cites plant-specific note 9, which states that the aging effect/mechanism of loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling is not in the GALL Report for this component, material, and environment; however, it is applicable to this combination. Plant-specific note 9 also states that the Open-Cycle Cooling Water System Program is used to manage the aging effects for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because loss of material, although rare and generally insignificant, may occur in nickel-alloy components exposed to raw water, but other aging effects addressed by the GALL Report (e.g., cracking) are essentially unknown for this combination of material and environment.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. The staff finds the applicant's proposal to manage aging using this AMP acceptable because: (1) nickel-alloy components exposed to raw water are not subject to any mechanisms which lead to loss of material which are not present in steel, (2) the rate of material loss from steel components when exposed to raw water is significantly greater than for nickel alloys, and (3) the GALL Report states that the Open-Cycle Cooling Water System Program is an adequate means to manage aging of steel components exposed to raw water. Since the Open-Cycle Cooling Water System Program is an acceptable means to manage the aging of a material which is more susceptible to loss of material than nickel alloys, the staff finds that this AMP will also be satisfactory in managing the aging of nickel alloys.

The staff's evaluation for reinforced concrete exposed to raw water, which is being managed for cracking, loss of bond, and loss of material (spalling, scaling)/corrosion of embedded steel by the Open-Cycle Cooling Water System Program, is documented in SER Section 3.3.2.3.4.

In LRA Table 3.3.2-23, the applicant stated that the loss of material due to crevice corrosion and reduction of heat transfer due to fouling for titanium heat exchanger components exposed to closed-cycle cooling water is not addressed by the GALL Report. The applicant cited generic note F for this item, indicating that the material is not in the GALL Report for this component. The applicant also stated that the aging effect is managed by the Closed-Cycle Cooling Water System Program.

The staff confirmed that the GALL Report does not include an AERM or AMP for titanium alloy components exposed to a closed-cycle cooling water environment.

The staff reviewed the applicant's Closed-Cycle Cooling Water System Program evaluated in SER Section 3.0.3.2.3. The staff finds the monitoring program acceptable because: (1) it performs condition monitoring, visual inspections, and NDEs to determine component functionality from the loss of material due to crevice corrosion and heat transfer due to fouling; and (2) the program is being enhanced to include a one-time inspection in areas of stagnant flow. The condition monitoring, visual inspections, and NDEs are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

In LRA Table 3.3.2-23, the applicant stated that titanium heat exchanger components exposed to closed-cycle cooling water (external) is not addressed by the GALL Report. The applicant cited generic note F for this item, indicating that no AMP is needed for this component, material, and environment combination. The applicant also stated that titanium material is corrosion resistant in water up to 260 °C (500 °F) due to a protective oxide film. The applicant further stated that this was consistent with plant operating experience and that no AMP is needed.

The staff confirms that the GALL Report does not include an AERM or AMP for titanium alloy components exposed to closed-cycle cooling water (external) environments.

The staff further reviewed the applicant's component, material, and environment combination, as well as other items in LRA Table 3.3.2-23. The staff determines that the applicant has also indicated a loss of material due to crevice corrosion and reduction of heat transfer due to fouling that can occur with this material, component, and environment. In that instance, the applicant identified the Closed-Cycle Cooling Water Program as the AMP. The staff notes that based on multiple references (e.g., AZo Journal of Materials Online, Britannica Encyclopedia, Key to Metals Database (online) Article 24), titanium is resistant to pitting, general, and crevice corrosion and SCC in salt water and turbine exhaust steam environments in essence due to its formation of very stable, continuous, highly adherent, and protective oxide films on metal surfaces. Based on these references, the staff also notes that due to its corrosion resistance capabilities, it is widely used in the refinery industry for condenser tubing and the aerospace industry in temperature applications up to 600 °C. The staff finds the applicant's proposal that there are no other AERMs other than the reduction of heat transfer acceptable based on titanium's resistance to pitting, general, and crevice corrosion and SCC in closed-cycle cooling water.

In LRA Table 3.3.2-23, the applicant stated that the reduction of heat transfer due to fouling and loss of material/macrofouling for titanium heat exchanger components exposed to raw water is not addressed by the GALL Report. The applicant cited generic note F for this item, indicating that the material is not in the GALL Report for this component. The applicant also stated that the aging effect is managed by the Open-Cycle Cooling Water System Program.

The staff confirms that the GALL Report does not include an AERM or AMP for titanium alloy components exposed to a raw water (internal) environment.

The staff reviewed the applicant's Open-Cycle Cooling Water System Program evaluated in SER Section 3.0.3.1.9. The staff finds the monitoring program acceptable because it uses performance monitoring, visual inspections, and NDEs to determine component function from the reduction of heat transfer due to fouling and loss of material due to macrofouling. The program includes surveillance and control techniques to manage the aging effect. The performance monitoring, visual inspections, and NDEs are consistent with the GALL Report and thus, the monitoring programs will adequately manage the aging effect.

In LRA Table 3.3.2-23, the applicant stated that titanium heat exchanger components exposed to air-indoor, dry air or gas (external), and air with borated water leakage is not addressed by the GALL Report. The applicant cited generic note F for this item, indicating that the material is not in the GALL Report for this component. The applicant also stated that no AMP is needed for this component, material, and environment combination. The applicant further stated that titanium material is corrosion resistant in water up to 260 °C (500 °F) due to a protective oxide film. The applicant stated that this was consistent with plant operating experience and that no AMP is needed.

The staff confirms that the GALL Report does not include an AERM or AMP for titanium alloy components exposed to indoor air, dry air or gas (external), and air with borated water leakage (external) environments.

The staff's review indicates that no AMP is needed for this material in an air environment, as titanium alloys exhibit excellent corrosion resistance (general, pitting, and crevice) up to 260 °C (500 °F) due to a protective oxide film. The staff further notes that based on multiple references (e.g., AZo Journal of Materials Online, Britannica Encyclopedia, Key to Metals Database (online) Article 24), titanium is resistant to pitting, general, and crevice corrosion and SCC in salt water and turbine exhaust steam environments in essence due to its formation of very stable, continuous, highly adherent, and protective oxide films on metal surfaces. Based on these references, the staff also notes that due to its corrosion resistance capabilities, it is widely used in the refinery industry for condenser tubing and the aerospace industry in temperature applications up to 600 °C. The staff finds the applicant's proposal that there are no other AERMs acceptable based on titanium's resistance to pitting, general, and crevice corrosion and SCC in indoor air, dry air or gas (external), and air with borated water leakage (external) environments.

In LRA Table 3.3.2-23, the applicant stated that the reduction of heat transfer due to fouling for titanium heat exchanger components exposed to lubricating oil is not addressed by the GALL Report. The applicant cited generic note F for this item, indicating that the material is not in the GALL Report for this component. The applicant also stated that the aging effect is managed by the One-Time Inspection and Lubricating Oil Analysis programs.

The staff confirms that the GALL Report does not include an AERM or AMP for titanium alloy components exposed to a lubricating oil environment.

The staff reviewed the applicant's use of the One-Time Inspection and Lubricating Oil Analysis programs evaluated in SER Sections 3.0.3.1.11 and 3.0.3.2.12, respectively. The staff finds the monitoring programs acceptable because: (1) they include analysis of oil to ensure that the physical properties of the lubricating oil are maintained within acceptable limits to ensure component intended function due to reduction of heat transfer due to fouling, and (2) the One-Time Inspection Program ensures the effectiveness of the Lubricating Oil Analysis Program. The One-Time Inspection and Lubricating Oil Analysis programs are consistent with the GALL Report and thus, the monitoring programs will adequately manage the aging effect.

In LRA Table 3.3.2-23, the applicant stated that titanium heat exchanger components exposed to lubricating oil (external) is not addressed by the GALL Report. The applicant cited generic note F for this item, indicating that the material is not in the GALL Report for this component. The applicant also stated that titanium material is corrosion resistant in lubricating oil due to a protective oxide film and thus, no aging effect is observed. The applicant further stated that this was consistent with plant operating experience and that no AMP is needed.

The staff confirms that the GALL Report does not include an AERM or AMP for titanium alloy components exposed to lubricating oil environments.

The staff reviewed the applicant's component, material, and environment combination, as well as other items in LRA Table 3.3.2-23. The staff determined that the applicant has also indicated a reduction of heat transfer due to fouling that can occur with this material, component, and environment. In that instance, the applicant identified the One-Time Inspection and Lubricating Oil Analysis programs as the AMPs. Thus, although the material is corrosion resistant in this environment, the applicant also has AMPs to evaluate a potential aging effect.

The staff's evaluation for copper alloy heat exchanger components exposed to wetted air and gas, which are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program and cite generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for stainless steel heat exchanger components exposed to wetted air or gas, which are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program and cite generic note H, is documented in SER Section 3.3.2.3.6.

In LRA Table 3.3.2-23, the applicant stated that stainless steel bolting components exposed to raw water are being managed for loss of preload due to self-loosening by the Bolting Integrity Program. The AMR line items reference generic note G.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.2. The staff finds the applicant's program acceptable to manage aging for these components because: (1) it has incorporated industry guidance on proper selection of bolting materials and lubricants and proper installation practices in order to prevent loss of preload from occurring, and (2) it includes detailed visual inspections of bolting which can detect if loss of preload due to self-loosening is occurring.

The staff's evaluation for carbon and low-alloy steel bolting exposed to groundwater and soil, which are being managed for loss of preload and loss of material by the Bolting Integrity Program, is documented in SER Section 3.3.2.3.4.

In LRA Table 3.3.2-23, the applicant stated that carbon and low-alloy steel bolting exposed externally to raw water is being managed for loss of preload due to thermal effects, gasket creep, and self-loosening and loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion by the Bolting Integrity Program. The applicant also stated that stainless steel bolting exposed externally to raw water is being managed for loss of material due to pitting and crevice corrosion by the Bolting Integrity Program. The AMR line items cite generic note G.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.2. The staff notes that the Bolting Integrity Program manages loss of material and loss of preload by performing visual inspections. The staff finds the applicant's proposed program for managing carbon, low-alloy, and stainless steel bolting for loss of preload and loss of material acceptable because the visual inspections used by the Bolting Integrity Program are appropriate for detection of these aging mechanisms and the program has incorporated industry guidance on proper selection of bolting materials, lubricants, and installation torque.

In LRA Table 3.3.2-23, the applicant stated that carbon steel with copper alloy cladding heat exchanger components exposed internally to raw water are being managed for loss of material due to erosion by the Open-Cycle Cooling Water System Program. The AMR line items cite generic note H. The applicant also stated that carbon steel with titanium cladding heat exchanger components exposed internally to raw water are being managed for loss of material due to macrofouling by the Open-Cycle Cooling Water System Program. The AMR line items cite generic note F.

The staff reviewed the applicant's Open-Cycle Cooling Water System Program and its evaluation is documented in SER Section 3.0.3.1.9. The staff notes that the Open-Cycle Cooling Water System Program manages loss of material by performing either visual inspections or NDEs and conducting maintenance inspections, preventive maintenance, and surveillance testing. The staff finds the applicant's management of carbon steel with either copper alloy cladding or titanium cladding heat exchanger components for loss of material acceptable because the visual inspections and NDEs used by the Open-Cycle Cooling Water System Program are appropriate for detection of these aging effects.

In LRA Table 3.3.2-23, the applicant stated that carbon steel with titanium alloy cladding and carbon or low-alloy steel with nickel-alloy cladding heat exchanger components exposed internally to dry air or gas have no AERMs and no AMP is necessary. The AMR line item for the carbon steel with titanium alloy cladding components cite generic note F, and the AMR line item for the carbon or low-alloy steel with nickel-alloy cladding components cite generic note G.

The applicant stated that the technical basis for determining that no aging effects would occur on the nickel-alloy cladding is that similar items in the GALL Report for nickel alloys exposed to dry air or gas, such as item IV.E-1, require no AMP. The applicant also stated that titanium alloy has superior resistance to corrosion in both air and water environments up to 260 °C (500 °F). The staff confirmed that titanium alloys are more resistant to corrosion than many materials and are only susceptible to corrosion in very low pH solutions and, therefore, titanium cladding is not expected to corrode under dry air conditions. The staff finds the applicant's determination that carbon steel with titanium alloy cladding or low-alloy steel with nickel-alloy cladding heat exchanger components exposed internally to dry air or gas do not require an AMP acceptable because aging effects are not expected to occur for these materials when exposed to dry air or gas.

In LRA Table 3.3.2-23, the applicant stated that aluminum bronze bolting, with 8 percent or more aluminum, exposed externally to indoor air are being managed for loss of preload due to thermal effects, gasket creep, and self-loosening and SCC by the Bolting Integrity Program.

The AMR line items cite generic note F for this item, indicating that the material is not in the GALL Report for this component.

The staff reviewed the associated line items in the LRA and confirms that the applicant has identified the correct aging effects for this component, material, and environment combination because aluminum bronze bolting can have comparable loss of preload as other bolting material. In addition, plant-specific operating experience identified cracking of the bolts associated with this line item. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff finds the applicant's proposal to manage aging using the proposed program acceptable because the Bolting Integrity Program employs visual inspection, which is consistent with the GALL Report for monitoring these aging degradations. In addition, as noted in the operating experience for the above program, as a result of finding broken bolts on the service water strainer, strainer inspections are being conducted every 3 years to preclude future failures.

In LRA Table 3.3.2-23, the applicant stated that aluminum heat exchanger components for the station air compressors-intercoolers and aftercooler exposed externally to wetted air or gas are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program. The AMR line item cites generic note H for this item, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirms that the applicant has identified the correct aging effects for this component, material, and environment combination because the GALL Report states that reduction of heat transfer results from fouling on heat transfer surfaces and that particulate fouling can be due to dust and corrosion products. The staff notes that the aluminum heat exchanger surfaces will be susceptible to this aging effect. The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff finds the applicant's proposal to manage aging using the above program acceptable because the Periodic Inspection Program uses visual inspections, which are capable of detecting dust and corrosion products on the aluminum heat exchanger surfaces to manage reduction of heat transfer by fouling.

In LRA Table 3.3.2-23, the applicant stated that aluminum bronze strainer bodies, with 8 percent or more aluminum, exposed internally to raw water are being managed for loss of material due to selective leaching by the Selective Leaching of Materials Program. The LRA line item cites generic note F for this item, indicating that the material is not in the GALL Report for this component.

The staff reviewed the associated line items in the LRA and confirms that the applicant has identified the correct aging effect for this component, material, and environment combination because, as noted in NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," aluminum bronze materials are susceptible to the selective leaching process. The staff's evaluation of the applicant's Selective Leaching of Materials Program is documented in SER Section 3.0.3.1.12. The staff finds the applicant's proposal to manage aging using the above program acceptable because the Selective Leaching of Materials Program uses visual inspection and hardness tests, which is consistent with the GALL Report, for monitoring this degradation mechanism.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.24 Auxiliary Systems – Service Water Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-24

The staff reviewed LRA Table 3.3.2-24, which summarizes the results of AMR evaluations for the service water ventilation system component groups.

In LRA Table 3.3.2-24, the applicant stated that copper alloy (greater than 15 percent Zn) bolting components exposed to outdoor air are being managed for loss of material by the Periodic Inspection Program. The AMR line item cites generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR result line items in the GALL Report where the material is copper alloy and the aging effect/mechanism is loss of material and confirms that for this environment, there are no entries in the GALL Report for this component and material.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff finds the monitoring program acceptable because it uses visual inspections which are appropriate to determine whether there is any loss of component function caused by loss of material due to exposure to an outdoor air environment. The visual inspections are consistent with the GALL Report and thus, the monitoring program will adequately manage the aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.25 Auxiliary Systems – Spent Fuel Cooling System – Summary of Aging Management Evaluation – LRA Table 3.3.2-25

The staff reviewed LRA Table 3.3.2-25, which summarizes the results of AMR evaluations for the spent fuel cooling system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.26 Auxiliary Systems – Switchgear and Penetration Area Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-26

The staff reviewed LRA Table 3.3.2-26, which summarizes the results of AMR evaluations for the switchgear and penetration area ventilation system component groups.

The staff's evaluation of elastomer door seals and flexible connections exposed to wetted air or gas (internal) having an aging effect of hardening and loss of strength due to elastomer degradation that will be managed by the Periodic Inspection Program with generic note G is documented in SER Section 3.3.2.3.1.

The staff's evaluation of elastomer door seals and flexible connections exposed to air with treated borated water leakage for which the applicant cited generic note G is documented in SER Section 3.3.2.3.1.

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 functions 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 system components and component groups of the following:

- auxiliary feedwater system
- main condensate and feedwater system
- main condenser and air removal system
- main steam system
- main turbine and auxiliaries system

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion system components and component groups. In LRA Table 3.4.1, "Summary of Aging Management Evaluations for Steam and Power Conversion," the applicant provided a summary comparison of its AMRs to those evaluated in the GALL Report for steam and power conversion system components and component groups.

The applicant's AMRs evaluated and incorporated plant-specific and industry operating experience in the determination of AERMs from plant-specific condition reports and discussions with site personnel and from the GALL Report and issues identified since its publication.

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 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 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 AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified 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 had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.4.2.1 and 3.4.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.4.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line 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 System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL 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	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Section 3.4.2.2.1)
Steel piping, piping components, and piping elements exposed to steam (3.4.1-2)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.2(1))
Steel heat exchanger components exposed to treated water (3.4.1-3)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.2.(1))
Steel piping, piping components, and piping elements exposed to treated water (3.4.1-4)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.2(1))
Steel heat exchanger components exposed to treated water (3.4.1-5)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.9)
Steel and stainless steel tanks exposed to treated water (3.4.1-6)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.2(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to lubricating oil (3.4.1-7)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.4.2.2.2(2))
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-8)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion and fouling	Plant-specific	Yes	Not applicable	Not applicable to Salem (see SER Section 3.4.2.2.3)
Stainless steel and copper alloy heat exchanger tubes exposed to treated water (3.4.1-9)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.4(1))
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (3.4.1-10)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.4.2.2.4(2))
Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil (3.4.1-11)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Buried Piping and Tank Surveillance or Buried Piping and Tank Inspection	No Yes	Buried Piping Inspection	Consistent with the GALL Report (see SER Section 3.4.2.2.5(1))
Steel heat exchanger components exposed to lubricating oil (3.4.1-12)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.4.2.2.5(2))
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-13)	SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.4.2.2.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water > 60 °C (140 °F) (3.4.1-14)	SCC	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.6)
Aluminum and copper alloy piping, piping components, and piping elements exposed to treated water (3.4.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.7(1))
Stainless steel piping, piping components, and piping elements; tanks; and heat exchanger components exposed to treated water (3.4.1-16)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.4.2.2.7(1))
Stainless steel piping, piping components, and piping elements exposed to soil (3.4.1-17)	Loss of material due to pitting and crevice corrosion	Plant-specific	Yes	Not applicable	Not applicable to Salem (see SER Section 3.4.2.2.7(2))
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.4.1-18)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to Salem (see SER Section 3.4.2.2.7(3))
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil (3.4.1-19)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	One-Time Inspection and Lubricating Oil Analysis	Consistent with the GALL Report (see SER Section 3.4.2.2.8)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel tanks exposed to air-outdoor (external) (3.4.1-20)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-21)	SCC and cracking due to cyclic loading	Bolting Integrity	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Steel bolting and closure bolting exposed to air with steam or water leakage, air-outdoor (external), or air-indoor uncontrolled (external) (3.4.1-22)	Loss of material due to general, pitting, and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (140 °F) (3.4.1-23)	SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report
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	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.4.1-25)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with the GALL Report

Component Group (GALL Report Item No.)	**Aging Effect/ Mechanism**	**AMP in GALL Report**	**Further Evaluation in GALL Report**	**AMP in LRA, Supplements, or Amendments**	**Staff Evaluation**
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-26)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.4.1-27)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Steel external surfaces exposed to air-indoor uncontrolled (external), condensation (external), or air-outdoor (external) (3.4.1-28)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-29)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to condensation (internal) or air-outdoor (internal) (3.4.1-30)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel heat exchanger components exposed to raw water (3.4.1-31)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (3.4.1-32)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Stainless steel heat exchanger components exposed to raw water (3.4.1-33)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System, Fire Water System, and Periodic Inspection	Consistent with the GALL Report (see SER Section 3.4.2.1.2)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water (3.4.1-34)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Copper alloy > 15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water, raw water, or treated water (3.4.1-35)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching of Materials	Consistent with the GALL Report
Gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water (3.4.1-36)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Steel, stainless steel, and nickel-based alloy piping, piping components, and piping elements exposed to steam (3.4.1-37)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel bolting and external surfaces exposed to air with borated water leakage (3.4.1-38)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-39)	SCC	Water Chemistry	No	Water Chemistry	Consistent with the GALL Report
Glass piping elements exposed to air, lubricating oil, raw water, and treated water (3.4.1-40)	None	None	NA	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Stainless steel, copper alloy, and nickel-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.4.1-41)	None	None	NA	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air-indoor controlled (external) (3.4.1-42)	None	None	NA	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.4.1-43)	None	None	NA	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (3.4.1-44)	None	None	NA	Not applicable	Not applicable to Salem (see SER Section 3.4.2.1.1)

The staff's review of the steam and power conversion system component groups followed several approaches. One approach, documented in SER Section 3.4.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.4.2.2, discusses the staff's review of AMR results for components 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, discusses the staff's review of AMR results for components 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 system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are 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 system components:

- Aboveground Non-Steel Tanks
- Bolting Integrity
- Boric Acid Corrosion
- Buried Piping Inspection
- Closed-Cycle Cooling Water System
- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Open-Cycle Cooling Water System
- Periodic Inspection
- Selective Leaching of Materials
- TLAA
- Water Chemistry

LRA Tables 3.4.2-1 through 3.4.2-5 summarize the AMRs for the steam and power conversion system components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line 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 line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

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

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

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

The staff notes that in LRA Table 3.4.2-1, there are AMR line items for a stainless steel tank exposed to treated water. The staff also notes that the LRA does not have a line item for the tank material exposed to an air or wetted gas internal environment as would occur when the tank is partially full. The staff further notes that the LRA line items manage the aging of the tank internals using the Water Chemistry and One-Time Inspection programs. The staff finds the existing line items acceptable because: (1) the Water Chemistry Program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, and (2) the One-Time Inspection Program will provide reasonable assurance that an aging effect is not occurring or that the aging effect is occurring slowly enough to not affect a component's intended function.

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).

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

LRA Table 3.4.1, item 3.4.1-20 addresses loss of material due to general, pitting, and crevice corrosion in steel tanks exposed to air-outdoor (external). The applicant stated that this line item is not applicable because there are no steel tanks exposed to air-outdoor (external) in the steam and power conversion system. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion systems that include steel tanks exposed to air-outdoor (external). The staff also reviewed the applicant's UFSAR and confirmed that no in-scope steel tanks exposed to air-outdoor (external) are present in the steam and power conversion systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1, item 3.4.1-21 addresses high-strength steel closure bolting exposed to air with steam or water leakage in the steam and power conversion system. The GALL Report recommends the use of GALL AMP XI.M18, "Bolting Integrity," to manage cracking due to cyclic loading or SCC for this component group. The applicant stated that this item is not applicable because there is no high-strength steel closure bolting in the steam and power conversion system. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion system that includes high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage is present in the steam and power conversion system and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1-1, item 3.4.1-24 addresses loss of material due to general, pitting, crevice, and galvanic corrosion for steel heat exchanger components exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because there are no steel heat exchanger components exposed to closed-cycle cooling water in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results that included the corresponding components in the closed-cycle cooling water environment. The staff also reviewed the UFSAR and confirmed that no in-scope steel heat exchanger components exposed to closed-cycle cooling water are present in applicable systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1-1, item 3.4.1-26 addresses loss of material due to pitting, crevice, and galvanic corrosion for copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because there are no corresponding components exposed to closed-cycle cooling water in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results that included the corresponding components in the closed-cycle cooling water environment. The staff also reviewed the UFSAR and confirmed that no in-scope copper alloy piping, piping components, or piping elements exposed to closed-cycle cooling water are present in applicable systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1-1, item 3.4.1-27 addresses reduction in heat transfer due to fouling for steel, stainless steel, and copper alloy heat exchanger components exposed to closed-cycle cooling water. The applicant stated that this item is not applicable because there are no corresponding components exposed to closed-cycle cooling water in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results that included the corresponding components in the closed-cycle cooling water environment. The staff also reviewed the UFSAR and confirmed that no in-scope steel, stainless steel, or copper alloy heat exchanger components exposed to closed-cycle cooling water are present in applicable systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1-1, item 3.4.1-31 addresses loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion for steel heat exchanger components exposed to raw water. The applicant stated that this item is not applicable because there are no steel heat exchanger components exposed to raw water in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results that included the corresponding components in a raw water environment. The staff also reviewed the UFSAR and confirmed that no in-scope steel heat exchanger components exposed to raw water are present in applicable systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1-1, item 3.4.1-32 addresses loss of material due to pitting, crevice, and microbiologically-influenced corrosion for stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water. The applicant stated that this item is not applicable because there are no stainless steel or copper alloy piping, piping components, or piping elements exposed to raw water in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results that included the corresponding components in a raw water environment. The staff also reviewed the UFSAR and confirmed that no in-scope stainless steel or copper alloy piping, piping components, or piping elements exposed to raw water are present in applicable systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1-1, item 3.4.1-34 addresses reduction of heat transfer due to fouling for steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water. The applicant stated that this item is not applicable because there are no corresponding components exposed to raw water with an aging mechanism of reduction of heat transfer due to fouling in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results that included the corresponding components in a raw water environment with the above noted aging effect. The staff also reviewed the UFSAR and confirmed that no corresponding in-scope components exposed to raw water are present in applicable systems and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1, item 3.4.1-36 addresses gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water. The GALL Report recommends the use of GALL AMP XI.M33, "Selective Leaching of Materials," to manage loss of material due to selective leaching for this component group. The applicant stated that this line item was not applicable because there are no steam and power conversion system piping, piping components, and piping elements fabricated from gray cast iron and exposed to soil, treated water, or raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion system that include gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water. The staff also noted that a search of the applicant's UFSAR did not find any evidence of gray cast iron piping, piping components, and piping elements in the steam and power conversion system exposed to soil, treated water, or raw water. Based on its review of the LRA and UFSAR, the staff confirmed that there are no in-scope gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water in the steam and power conversion system and, therefore, finds the applicant's determination acceptable.

LRA Table 3.4.1, item 3.4.1-40 addresses glass piping elements exposed to air, lubricating oil, raw water, and treated water. The applicant stated that this line item is not applicable because there are no glass piping elements exposed to air, lubricating oil, raw water, or treated water in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion systems that include glass piping elements exposed to air, lubricating oil, raw water, and treated water. The staff notes that the applicant stated that there is no AERM or recommended AMP for this material and component combination. The staff also notes that the GALL Report recommends that there is no AERM or AMP for this material and environment combination. The staff, therefore, finds the applicant's proposal that there is no AERM or AMP acceptable regardless of whether or not the material and environment combination exists in the steam and power conversion systems.

LRA Table 3.4.1, item 3.4.1-42 addresses steel piping, piping components, and piping elements externally exposed to controlled indoor air. The applicant stated that this line item is not applicable because all indoor air was assumed to be uncontrolled for the purposes of license renewal. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does have AMR results for steel piping, piping components, and piping elements externally exposed to indoor uncontrolled air and that those items are being managed by alternative line items applicable to indoor uncontrolled air. The staff, therefore, finds the applicant's determination acceptable because uncontrolled air is a more aggressive environment than controlled air and the items are being managed by appropriate alternative line items.

LRA Table 3.4.1, item 3.4.1-43 addresses steel and stainless steel piping, piping components, and piping elements in concrete. The applicant stated that this line item is not applicable because the applicant does not have any steel and stainless steel piping, piping components, and piping elements exposed to concrete in the steam and power conversion systems. The applicant also stated that there is no AERM or recommended AMP for this material and component combination. The staff notes that the GALL Report recommends that there is no AERM or AMP for this material and environment combination. The staff, therefore, finds the applicant's proposal that there is no AERM or AMP acceptable regardless of whether or not the material and environment combination exists in the steam and power conversion systems.

LRA Table 3.4.1, item 3.4.1-44 addresses steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas. The applicant stated that this line item is not applicable because the applicant does not have any steel, stainless steel, aluminum, or copper alloy piping, piping components, and piping elements exposed to gas in the steam and power conversion systems. The applicant also stated that there is no AERM or recommended AMP for this material and component combination. The staff notes that the GALL Report recommends that there is no AERM or AMP for this material and environment combination. The staff, therefore, finds the applicant's proposal that there is no AERM or AMP acceptable regardless of whether or not the material and environment combination exists in the steam and power conversion systems.

3.4.2.1.2 Loss of Material Due to General, Pitting, Crevice, Galvanic, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.4.1, item 3.4.1-33 addresses 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. The LRA credits the Fire Water System Program to manage aging for stainless steel flow elements, heat exchanger components, piping and fittings, pump casings, restricting orifice, strainer bodies, thermowells, and valve bodies in the fire protection system. The GALL Report recommends GALL AMP XI.M20, “Open-Cycle Cooling Water System,” to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The AMR line items also cite plant-specific note 9, indicating that the Fire Water System Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

The staff reviewed the applicant’s Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.6. In its review of components associated with LRA Table 3.4-1, item 3.4.1-33, the staff noted that the Fire Water System Program proposes to manage aging for these components through the use of periodic flushing, system performance testing, volumetric examinations, and visual inspections. The staff also noted that GALL AMP XI.M20 relies on implementation of the recommendations of GL 89-13, which includes using preventive measures, periodic visual inspections, and performance testing to manage these aging effects and is only applicable for components exposed to cooling water that transfers heat from safety-related components to the ultimate heat sink. The staff finds the LRA proposed AMP acceptable because: (1) the proposed preventive measures, performance monitoring, and inspection methods are effective for managing loss of material; and (2) the components are in the fire protection system and are not included within the scope of GL 89-13.

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).

3.4.2.1.3 Conclusion for AMRs Consistent with the GALL Report

The staff evaluated the applicant’s claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant’s consideration of recent operating experience and proposals for managing the associated 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 with the GALL Report AMRs. Therefore, the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.4.2.2 provides further evaluation of aging management, as recommended by the GALL Report for the steam and power conversion system components. The applicant provided 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 material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling
- reduction of heat transfer due to fouling
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- cracking due to SCC
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, and galvanic 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 GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues and reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.4.2.2. The staff's review of the applicant's further evaluations follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1 states fatigue is a TLAA as defined in 10 CFR 54.3. Furthermore, TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that the evaluation of metal fatigue as a TLAA for the auxiliary feedwater, component cooling, main condensate and feedwater, and main steam systems is discussed 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 state 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 the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff also reviewed LRA Section 3.4.2.2.1 and the applicant's AMR items referenced to this LRA Section against the staff's AMR items for evaluating cumulative fatigue damage as given in AMR item 1 in the GALL Report, Volume 1, Table 4 and the AMR items in Section VIII of the GALL Report, Volume 2, Revision 1 that derive from this GALL Report, Volume 1 AMR item.

With regard to LRA Table 3.4.1, item 3.4.1-1, the staff noted that GALL AMR items VIII.B1-10, VIII.D1-7, and VIII.G-37 identify cumulative fatigue damage as an applicable aging effect for steel piping, piping components, and piping elements and recommends that the TLAA on metal fatigue be used to manage this aging effect. The applicant included an applicable line item in LRA Tables 3.4.2-1, 3.4.2-2, 3.4.2-4, and 3.3.2-5 for steel piping and fittings that received implicit fatigue analysis calculations in accordance with design code requirements for ASME Code Section III Class 2 or 3 components or ANSI B31.1 components consistent with the recommendations in the SRP-LR. Based on its review, the staff finds the applicant's AMR analysis on cumulative fatigue piping and fittings to be acceptable because it is consistent with the recommendations in SRP-LR Section 3.4.2.2.1. The staff evaluates the TLAA analysis for the piping and fittings component in SER Section 4.3.3.

Based on the programs identified, the staff concludes that the applicant meets 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 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).

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

The staff reviewed LRA Section 3.4.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2.

(1) LRA Section 3.4.2.2.2, item 1 is referenced by LRA Table 3.4.1, items 3.4.1-2, 3.4.1-3, 3.4.1-4, and 3.4.1-6 and addresses steel piping, piping components, piping elements, heat exchanger components, tanks, turbine casings, and steel components exposed to treated water or steam, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that for the associated components in the auxiliary feedwater system, component cooling system, demineralized water system, heating water and heating steam system, main condensate and feedwater system, main condenser and air removal system, main steam system, RCS, sampling system, and SGs, the Water Chemistry and One-Time Inspection programs will be used to manage loss of material due to general, pitting, and crevice corrosion.

    The staff reviewed LRA Section 3.4.2.2.2, item 1 against the criteria described in SRP-LR Section 3.4.2.2.2, item 1, which state that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water and in steel piping, piping components, and piping elements exposed to steam. The SRP-LR also states that the existing AMP relies on monitoring and control of water chemistry to mitigate degradation and that a one-time inspection of selected components at susceptible locations is an acceptable method to verify the effectiveness of the water chemistry controls.

    The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The staff noted that the applicant's One-Time Inspection Program includes the determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience and the identification of inspection locations based on the aging effect. In its review of components associated with items 3.4.1-2, 3.4.1-3, 3.4.1-4, and 3.4.1-6, the staff finds the applicant's proposal to manage aging using the above programs acceptable because: (a) the Water Chemistry Program will assure that contaminants are maintained below applicable limits which have been shown to limit loss of material due to general, pitting, and crevice corrosion, and (b) the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including samples in low or stagnant flow areas.

(2) LRA Section 3.4.2.2.2.2, referenced by LRA Table 3.4.1, item 3.4.1-7, addresses steel piping, piping components, and piping elements exposed to lubricating oil, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage the loss of material through examination of susceptible locations in steel piping, piping components, and piping elements exposed to lubricating oil.

The staff reviewed LRA Section 3.4.2.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2, item 2, which state that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-7, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (a) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (b) the applicant stated that the One-Time Inspection Program will be used to examine steel, piping components, and piping elements to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.4.2.2.2, item 2 and, therefore, the applicant's AMR is consistent with GALL Report item VIII.G-35.

Based on its review and evaluation of the programs identified above, the staff concludes that the applicant's programs satisfy SRP-LR Section 3.4.2.2.2 criteria. For those line items that apply to LRA Section 3.4.2.2.2, 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).

3.4.2.2.3 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

The staff reviewed LRA Section 3.4.2.2.3 against the criteria in SRP-LR Section 3.4.2.2.3.

LRA Section 3.4.2.2.3, associated with LRA Table 3.4.1, item 3.4.1-8, addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling in steel piping, piping components, and piping elements exposed to raw water. The applicant stated that this line item is not applicable because this material, environment, and aging effect does not exist in the plant. The staff reviewed LRA Sections 2.3.4 and 3.4, the UFSAR, and TSs and confirmed that no in-scope steel piping, piping components, and piping elements exposed to raw water are present in the steam and power conversions systems and, therefore, finds the applicant's determination acceptable.

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.4.2.2.4 against the criteria in SRP-LR Section 3.4.2.2.4.

(1) LRA Section 3.4.2.2.4, item 1 is referenced by LRA Table 3.4.1, item 3.4.1-9 and addresses stainless steel or copper alloy heat exchanger tubes exposed to a treated water environment, which are being managed for reduction in heat transfer due to fouling by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program to manage the reduction of heat transfer due to fouling in the auxiliary feedwater and component cooling systems.

    The staff reviewed LRA Section 3.4.2.2.4, item 1 against the criteria in SRP-LR Section 3.4.2.2.4, item 1, which state that reduction of heat transfer due to fouling could occur for stainless steel and copper alloy heat exchanger tubes exposed to treated water. The SRP-LR also states that the existing AMP relies on control of water chemistry to manage reduction of heat transfer due to fouling, but these controls may not always have been adequate to preclude fouling. The SRP-LR further states that the effectiveness of the water chemistry control program should be verified and that a one-time inspection is an acceptable method to verify effectiveness.

    The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-9, the staff finds the applicant's proposal to manage aging with the above programs acceptable because the Water Chemistry Program provides for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of heat transfer due to fouling. In addition, the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by determining sample sizes based on materials, environments, aging mechanisms, and operating experience and by identifying inspection locations and examination techniques, including acceptance criteria, based on the aging effects for which the components are being examined.

(2) LRA Section 3.4.2.2.4.2, referenced by LRA Table 3.4.1, item 3.4.1-10, addresses steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil, which are being managed for reduction in heat transfer due to fouling by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage reduction in heat transfer through examination of susceptible locations in stainless steel heat exchanger tubes exposed to lubricating oil.

The staff reviewed LRA Section 3.4.2.2.4.2 against the criteria in SRP-LR Section 3.4.2.2.4, item 2, which state that reduction of heat transfer due to fouling could occur for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on monitoring and control of lube oil chemistry to mitigate reduction of heat transfer due to fouling. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that fouling does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to verify the effectiveness of the lube oil chemistry control program for which a one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-10, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (a) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (b) the applicant stated that the One-Time Inspection Program will be used to examine steel, stainless steel, and copper alloy heat exchanger tubes to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.4.2.2.4, item 2 and, therefore, the applicant's AMR is consistent with GALL Report item VIII.G-12.

Based on its review and evaluation of the programs identified above, the staff concludes that the applicant's programs satisfy SRP-LR Section 3.4.2.2.4 criteria. For those line items that apply to LRA Section 3.4.2.2.4, 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).

3.4.2.2.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.5 against the criteria in SRP-LR Section 3.4.2.2.5.

(1) LRA Section 3.4.2.2.5.1 refers to Table 3.4.1, item 3.4.1-11 and addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping, piping components, piping elements, and tanks with or without coating exposed to soil. The applicant stated that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in the steel piping, piping components, and piping elements exposed to soil in the auxiliary feedwater system and demineralized water system will be managed by the Buried Piping Inspection Program.

The staff reviewed LRA Section 3.4.2.2.5.1 against the criteria in SRP-LR Section 3.4.2.2.5.1, which state that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion could occur in steel piping, piping components, piping elements, and tanks, with or without coating or wrapping, in a soil environment. The SRP-LR also states that the effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

The staff reviewed the applicant's Buried Piping Inspection Program, which is evaluated in SER Section 3.0.3.2.10. The staff finds that the credited program is acceptable because the Buried Piping Inspection Program relies on preventive measures such as coating and wrapping to mitigate corrosion and periodic visual inspections of external surfaces to identify coating degradation and, therefore, ensures that the loss of material aging effect will be adequately managed.

(2) LRA Section 3.4.2.2.5.2, referenced by LRA Table 3.4.1, item 3.4.1-12, addresses steel heat exchanger components exposed to lubricating oil, which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to lubricating oil in the auxiliary feedwater system and RCS.

The staff reviewed LRA Section 3.4.2.2.5.2 against the criteria in SRP-LR Section 3.4.2.2.5, item 2, which state that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion could occur in steel heat exchanger components exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-12, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (a) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (b) the applicant stated that the One-Time Inspection Program will be used to examine steel heat exchanger components to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.4.2.2.5, item 2 and, therefore, the applicant's AMR is consistent with GALL Report item VIII.G-6.

Based on its review and evaluation of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.5 criteria. For those line items that apply to LRA Section 3.4.2.2.5, 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).

3.4.2.2.6 Cracking Due to Stress-Corrosion Cracking

The staff reviewed LRA Section 3.4.2.2.6 against the criteria in SRP-LR Section 3.4.2.2.6.

LRA Section 3.4.2.2.6 addresses cracking due to SCC, stating that item 3.4.1-13 is applicable to BWRs only and is not used for the Salem units, which are PWRs. This item pertains to SCC in stainless steel piping, piping components, and piping elements exposed to steam. The staff noted that the applicant's plant type is PWR and agrees that this line item is not applicable.

LRA Section 3.4.2.2.6 also refers to Table 3.4.1, item 3.4.1-14 and addresses SCC in stainless steel piping, piping components, piping elements, heat exchanger components, SG components, and tanks exposed to treated water that is greater than 60 °C (140 °F) in the SGs, demineralized water system, sampling system, auxiliary feedwater system, heating water and heating steam system, main condensate and feedwater system, and main steam system. The LRA states that the Water Chemistry Program and One-Time Inspection Program will be implemented to manage the aging effect for these components except for the SG components. The applicant also indicated that the One-Time Inspection Program is used to verify the effectiveness of the Water Chemistry Program for the components other than the SG components. In addition, as described in applicant's letter dated October 8, 2010, the revised LRA states that the aging effect of the SG components (Unit 2 SG feedwater rings, spray nozzles and inspection port diaphragms) are managed by the Water Chemistry Program and Steam Generator Tube Integrity Program. The applicant further stated that the Steam Generator Tube Integrity Program is used to verify the effectiveness of the Water Chemistry Program for the SG components.

The staff reviewed LRA Section 3.4.2.2.6 against the criteria in SRP-LR Section 3.4.2.2.6, which state that cracking due to SCC could occur in the stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60 °C (140 °F) and for stainless steel piping, piping components, and piping elements exposed to steam. The SRP-LR further states that the existing AMP relies on monitoring and control of water chemistry to manage the effects of aging. However, the SRP-LR indicates that high concentrations of impurities at crevices and locations with stagnant flow conditions could cause SCC and, therefore, the GALL Report recommends that the effectiveness of the water chemistry program should be verified to ensure that SCC does not occur. The SRP-LR further states that a one-time inspection of selected components at susceptible locations is an acceptable method to ensure SCC does not occur.

The staff reviewed the LRA and identified in Table 3.4.1, item 3.4.1-14 and Tables 3.1.2-4, 3.3.2-10, 3.3.2-22, 3.4.2-1, 3.4.2-2, and 3.4.2-4 that the applicant credited the Water Chemistry Program and One-Time Inspection Program to manage SCC of stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60 °C (140 °F). In its review, the staff also identified that the applicant credited the Water Chemistry Program and Steam Generator Tube Integrity Program to manage SCC of the stainless steel SG components exposed to treated water greater than 60 °C (140 °F). The staff reviewed the applicant's Water Chemistry Program, One-Time Inspection Program and Steam Generator Tube Integrity Program. The staff's evaluations are documented in SER Sections 3.0.3.1.2, 3.0.3.1.11, and 3.0.3.1.8, respectively. The staff finds that the credited programs are adequate to manage the aging effect because: (1) the Water Chemistry Program monitors the plant water chemistry control parameters against the established parameter limits and, if a parameter exceeds the limit, the program performs adequate actions such that the water chemistry control continues to mitigate the aging effect; (2) the One-Time Inspection Program includes a one-time inspection of selected components to verify the effectiveness of the Water Chemistry Program consistent with the GALL Report; (3) the one-time inspection can ensure that significant degradation does not occur and that the component's intended function is maintained during the period of extended operation; (4) the Steam Generator Tube Integrity Program implements the inspections of secondary side upper internals, which include feedwater rings and spray nozzles, and the secondary side visual inspections as recommended in the EPRI Steam Generator Integrity Assessment Guidelines that the LRA references consistent with the GALL Report; and (5) the SG inspections are adequate to confirm the effectiveness of the Water Chemistry Program. On the basis of its review, the staff finds that the applicant's AMR results satisfied the acceptance criteria in SRP-LR Section 3.4.2.2.6.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.6 criteria. For those items that apply to LRA Section 3.4.2.2.6, 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).

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.4.2.2.7 against the criteria in SRP-LR Section 3.4.2.2.7.

(1) LRA Section 3.4.2.2.7, item 1 is referenced by Table 3.4.1, items 3.4.1-6, 3.4.1-15, and 3.4.1-16 and addresses aluminum, copper alloy, and stainless steel piping, piping components, piping elements, tanks, valves, and heat exchanger components exposed to treated water, which are being managed for loss of material due to pitting and crevice corrosion by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that, for the components exposed to treated water in the auxiliary feedwater system, chemical and volume control system, component cooling system, demineralized water system, main condensate and feedwater system, heating water and heating steam system, main condenser and air removal system, main steam system, RCS, sampling system, and SGs, the Water Chemistry and One-Time Inspection programs will be used to manage loss of material due to pitting and crevice corrosion.

The staff reviewed LRA Section 3.4.2.2.7, item 1 against the criteria described in SRP-LR Section 3.4.2.2.7, item 1, which state that loss of material due to pitting and crevice corrosion could occur for stainless steel, aluminum, and copper alloy piping, piping components, and piping elements and for stainless steel tanks and heat exchanger components exposed to treated water. The SRP-LR also states that the existing AMP relies on monitoring and control of water chemistry to mitigate degradation and that a one-time inspection of selected components at susceptible locations is an acceptable method to verify the effectiveness of the chemistry control program.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. The staff notes that the applicant's One-Time Inspection Program includes the determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience and the identification of inspection locations is based on the aging effect. In its review of components associated with items 3.4.1-6, 3.4.1-15, and 3.4.1-16, the staff finds the applicant's proposal to manage aging using the above programs acceptable because: (a) the Water Chemistry Program will assure that contaminants are maintained below applicable limits which have been shown to minimize corrosion, and (b) the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including samples from low or stagnant flow areas.

In addition to the above components, in its review of components associated with item 3.4.1-16 in LRA Table 3.1.2-4, the staff noted that the applicant proposed to manage aging for the stainless steel SG tube support plates exposed to treated water greater than 60 °C (140 °F) for loss of material due to pitting and crevice corrosion through the Steam Generator Tube Integrity and Water Chemistry programs. The applicant stated that this was consistent with the GALL Report for material, environment, and aging effect, but a different AMP was credited. However, as noted above for item 3.4.1-16, the GALL Report recommends that the effectiveness of the water chemistry controls be verified through a one-time inspection, and it was unclear to the staff how the Steam Generator Tube Integrity Program would be used to verify the effectiveness of the Water Chemistry Program. By letter dated June 17, 2010, the staff issued RAI 3.4.1-01, requesting that the applicant provide the basis for using the Steam Generator Tube Integrity Program to verify the effectiveness of the Water Chemistry Program. In its response dated July 15, 2010, the applicant revised the above line item to be consistent with the GALL Report to indicate that the One-Time Inspection Program would be used to verify the effectiveness of the Water Chemistry Program for this line item.

However, after additional discussions with the staff on September 9, 2010, the applicant submitted additional information by letter dated October 8, 2010, regarding various SG components. The applicant revised LRA Section 3.4.2.2.7, item 1 by removing SGs from the discussion regarding the use of the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program, and added a discussion regarding the use of the Steam Generator Tube Integrity Program to verify water chemistry effectiveness for components in the SGs. In addition, the applicant revised LRA Table 3.4.1, item 3.4.1-16 and LRA Table 3.1.2-4 for loss of material due to pitting and crevice corrosion in stainless steel SG components to reflect comparable information.

The staff finds the applicant's response and changes to the LRA acceptable because the Steam Generator Tube Integrity Program includes preventive measures to mitigate degradation related to corrosion phenomena and condition monitoring activities through ISIs of SG tube supports and internals to detect degradation including loss of material. Based on the above, the staff's concern described in RAI 3.4.1-01 is resolved.

(2) LRA Section 3.4.2.2.7, item 2, associated with LRA Table 3.4.1, item 3.4.1-17, addresses loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this line item is not applicable because the stainless steel piping, piping components, and piping elements external surfaces in the steam and power conversion system are not exposed to soil. The staff reviewed LRA Sections 2.3.4 and 3.4 and the UFSAR and confirmed that no in-scope stainless steel piping, piping components, and piping elements exposed to soil are present in the steam and power conversion system and, therefore, finds the applicant's determination acceptable.

(3) LRA Section 3.4.2.2.7, item 3, associated with LRA Table 3.4.1, item 3.4.1-18, addresses loss of material due to pitting and crevice corrosion and could occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil. The applicant stated that this line item is not applicable because there are no copper alloy piping, piping components, and piping elements exposed to lubricating oil in the steam and power conversion system. The staff reviewed LRA Sections 2.3.4 and 3.4 and the UFSAR and confirmed that no in-scope copper alloy piping, piping components, and piping elements exposed to lubricating oil are present in the steam and power conversion system and, therefore, finds the applicant's determination acceptable.

Based on its review and evaluation of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.7 criteria. For those line items that apply to LRA Section 3.4.2.2.7, 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).

3.4.2.2.8 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.8 against the criteria in SRP-LR Section 3.4.2.2.8.

LRA Section 3.4.2.2.8, referenced by LRA Table 3.4.1, item 3.4.1-19, addresses stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil, which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil.

The staff reviewed LRA Section 3.4.2.2.8 against the criteria in SRP-LR Section 3.4.2.2.8, which state that loss of material due to pitting, crevice, and microbiologically-influenced corrosion could occur in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program for which a one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-19, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because: (1) the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and (2) the applicant stated that the One-Time Inspection Program will be used to examine stainless steel piping, piping components, piping elements, and heat exchanger components to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.4.2.2.8 and, therefore, the applicant's AMR is consistent with GALL Report items VIII.G-3 and VIII.A-9.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.8 criteria. For the line items that apply to LRA Section 3.4.2.2.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effect of aging will be adequately managed so that the intended function(s) will be maintained with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

LRA Section 3.4.2.2.9 is referenced by LRA Table 3.4.1, item 3.4.1-5 and addresses loss of material due to general, pitting, crevice, and galvanic corrosion for steel heat exchanger components exposed to treated water, which are being managed by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program for steel heat exchanger components in the main condensate and feedwater system.

The staff reviewed LRA Section 3.4.2.2.9 against the criteria in SRP-LR Section 3.4.2.2.9, which state that loss of material due to general, pitting, crevice, and galvanic corrosion can occur for steel heat exchanger components exposed to treated water. The SRP-LR also states that the existing AMP relies on control of water chemistry to manage this aging effect, but control of water chemistry does not preclude this aging effect at locations of stagnant flow conditions. The SRP-LR further states that the effectiveness of the water chemistry control program should be verified to ensure that corrosion does not occur and that a one-time inspection of selected components at susceptible locations is an acceptable method to verify the program's effectiveness.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.11, respectively. In its review of items associated with item 3.4.1-5, the staff finds the applicant's proposal to manage aging using the above programs acceptable because: (1) the Water Chemistry Program provides for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude corrosion, and (2) the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by determining sample sizes based on materials, environments, aging mechanisms, and operating experience and by identifying inspection locations and examination techniques, including acceptance criteria, based on the aging effects for which the components are being examined.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.9 criteria. For those line items that apply to LRA Section 3.4.2.2.9, 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).

3.4.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-5, the staff reviewed additional details of 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 3.4.2-5, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line 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 line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line 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 aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.4.2.3.1 Steam and Power Conversion System – Auxiliary Feedwater System – Summary of Aging Management Evaluation – LRA Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMRs for the auxiliary feedwater system component groups.

The staff's evaluation for stainless steel tanks exposed externally to soil, which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Aboveground Non-Steel Tanks Program and cite generic note G, is documented in SER Section 3.3.2.3.2.

3.4.2.3.2 Steam and Power Conversion System – Main Condensate and Feedwater System – Summary of Aging Management Evaluation – LRA Table 3.4.2-2

The staff reviewed LRA Table 3.4.2-2, which summarizes the results of AMR evaluations for the main condensate and feedwater system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.4.2.1.

3.4.2.3.3 Steam and Power Conversion System – Main Condenser and Air Removal System – Summary of Aging Management Evaluation – LRA Table 3.4.2-3

The staff reviewed LRA Table 3.4.2-3, which summarizes the results of AMRs for the main condenser and air removal system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.4.2.1.

3.4.2.3.4 Steam and Power Conversion System – Main Steam System – Summary of Aging Management Evaluation – LRA Table 3.4.2-4

The staff reviewed LRA Table 3.4.2-4, which summarizes the results of AMRs for the main steam system component groups.

The staff's review did not find any line items indicating plant-specific notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with notes A through E is documented in SER Section 3.4.2.1.

3.4.2.3.5 Steam and Power Conversion System – Main Turbine and Auxiliaries System – Summary of Aging Management Evaluation – LRA Table 3.4.2-5

The staff reviewed LRA Table 3.4.2-5, which summarizes the results of AMRs for the main turbine and auxiliaries system component groups.

In LRA Table 3.4.2-5, the applicant stated that aluminum valve bodies exposed to lubricating oil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The AMR line item cites generic note G for this item, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effect for this component, material, and environment combination because, as noted in NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," aluminum is susceptible to this set of aging mechanisms in fuel oil environments. As such, aluminum would be comparably susceptible in lubricating oil environments. The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.1.11, respectively. The staff finds the applicant's proposal to manage aging with the above programs acceptable because: (1) the Lubricating Oil Analysis Program provides for periodic sampling to maintain contaminants at limits shown to preclude corrosion, and (2) the effectiveness of this program will be verified with the One-Time Inspection Program, which determines the sample size based on materials, fabrication, environment, plausible aging mechanism, and operating experience and identifies inspection locations and examination techniques based on aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3 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 be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containments, structures, and component supports of the following:

- auxiliary building
- component supports commodity group
- containment structure
- fire pump house
- fuel handling building
- office buildings
- penetration areas
- pipe tunnel
- piping and component insulation commodity group
- SBO yard buildings
- service building
- service water accumulator enclosures
- service water intake
- shoreline protection and dike
- switchyard
- turbine building
- yard structures

3.5.1 Summary of Technical Information in the Application

LRA Section 3.5 provides AMR results for the containment, structures, and component supports groups. LRA Table 3.5-1, "Summary of Aging Management Evaluations for Structures and Component Supports," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the structures and component supports 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 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 the AMR items that the applicant had identified as being consistent with the GALL Report 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 3.5.2.1.

The staff also conducted a review of 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 3.5.2.2 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 line 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 (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
PWR Concrete (Reinforced and Prestressed) and Steel Containments					
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable) (3.5.1-1)	Aging of accessible and inaccessible concrete areas due to aggressive chemical attack and corrosion of embedded steel	ISI (IWL) and for inaccessible concrete, an examination of representative samples of below-grade concrete and periodic monitoring of groundwater if environment is non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes	ASME Section XI, Subsection IWL and Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.1(1))
Concrete elements: all (3.5.1-2)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring. If a dewatering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes	Structures Monitoring Program and ASME Section XI, Subsection IWL	Consistent with the GALL Report (see SER Sections 3.5.2.1.7 and 3.5.2.2.1(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete elements: foundation, subfoundation (3.5.1-3)	Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring. If a dewatering system is relied upon to control erosion of cement from porous concrete subfoundations, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.1(2))
Concrete elements: dome, wall, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1-4)	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.1(3))
Steel elements: drywell; torus; drywell head; embedded shell and sand pocket regions; drywell support skirt; torus ring girder; downcomers; liner plate, ECCS suction header, support skirt, region shielded by diaphragm floor, suppression chamber (as applicable) (3.5.1-5)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel elements: steel liner, liner anchors, integral attachments (3.5.1-6)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	ASME Section XI, Subsection IWE and 10 CFR 50, Appendix J	Consistent with the GALL Report (see SER Section 3.5.2.2.1(4))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Prestressed containment tendons (3.5.1-7)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to Salem (see SER Sections 3.5.2.1.1 and 3.5.2.2.1(5))
Steel and stainless steel elements: vent line, vent header, vent line bellows; downcomers (3.5.1-8)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to PWRs (see SER Sections 3.5.2.1.1 and 3.5.2.2.1(6))
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-9)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.1(6))
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (3.5.1-10)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds.	Yes	ASME Section XI, Subsection IWE and 10 CFR Part 50 Appendix J	Consistent with the GALL Report (see SER Section 3.5.2.2.1(7))
Stainless steel vent line bellows (3.5.1-11)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J and additional appropriate examination/ evaluation for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable to PWRs (See SER Sections 3.5.2.1.1 and 3.5.2.2.1(7))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-12)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J and supplemented to detect fine cracks	Yes	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.1(8))
Steel, stainless steel elements, dissimilar metal welds: torus; vent line; vent header; vent line bellows; downcomers (3.5.1-13)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J and supplemented to detect fine cracks	Yes	Not applicable	Not applicable to PWRs (see SER Sections 3.5.2.1.1 and 3.5.2.2.1(8))
Concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable) (3.5.1-14)	Loss of material (scaling, cracking, and spalling) due to freeze-thaw	ISI (IWL). Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	ASME Section XI, Subsection IWL	Consistent with the GALL Report (see SER Section 3.5.2.2.1(9))
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1-15)	Cracking due to expansion and reaction with aggregate; increase in porosity and permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Yes	ASME Section XI, Subsection IWL	Consistent with the GALL Report (see SER Section 3.5.2.2.1(10))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Seals, gaskets, and moisture barriers (3.5.1-16)	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Personnel airlock, equipment hatch and CRD hatch locks, hinges, and closure mechanisms (3.5.1-17)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges, and closure mechanisms	10 CFR Part 50, Appendix J and plant TSs	No	10 CFR Part 50, Appendix J	Consistent with the GALL Report
Steel penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch, and CRD hatch (3.5.1-18)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Steel elements: stainless steel suppression chamber shell (inner surface) (3.5.1-19)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel elements: suppression chamber liner (interior surface) (3.5.1-20)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel elements: drywell head and downcomer pipes (3.5.1-21)	Fretting or lockup due to mechanical wear	ISI (IWE)	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Prestressed containment: tendons and anchorage components (3.5.1-22)	Loss of material due to corrosion	ISI (IWL)	No	Not applicable	Not applicable to Salem (see SER Section 3.5.2.1.1)
Safety-Related and Other Structures and Component Supports					
All Groups except Group 6: interior and above-grade exterior concrete (3.5.1-23)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring	Yes, if not within the scope of the Structures Monitoring Program	Structures Monitoring Program and Fire Protection	Consistent with the GALL Report (see SER Sections 3.5.2.1.9 and 3.5.2.2.2(1))
All Groups except Group 6: interior and above-grade exterior concrete (3.5.1-24)	Increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring	Yes, if not within the scope of the Structures Monitoring Program	Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(1))
All Groups except Group 6: steel components: all structural steel (3.5.1-25)	Loss of material due to corrosion	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.	Yes, if not within the scope of the Structures Monitoring Program	Structures Monitoring Program and Protective Coating Monitoring and Maintenance Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
All Groups except Group 6: accessible and inaccessible concrete: foundation (3.5.1-26)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes, if not within the scope of the Structures Monitoring Program, or for inaccessible areas located in moderate to severe weathering conditions	Structures Monitoring Program and Fire Protection	Consistent with the GALL Report (see SER Sections 3.5.2.1.9 and 3.5.2.2.2(1))
All Groups except Group 6: accessible and inaccessible interior/exterior concrete (3.5.1-27)	Cracking due to expansion due to reaction with aggregates	Structures Monitoring. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if not within the scope of the Structures Monitoring Program. No for inaccessible areas if concrete was constructed in accordance with recommendations in ACI 201.2R-77	Not applicable	Not applicable to Salem (see SER Sections 3.5.2.2.2(1) and 3.5.2.2.2(2))
Groups 1-3, 5-9: All (3.5.1-28)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring. If a dewatering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes, if not within the scope of the Structures Monitoring Program, or a dewatering system is relied upon	Structures Monitoring Program and Fire Protection	Consistent with the GALL Report (see SER Sections 3.5.2.1.7, 3.5.2.2.2(1), and 3.5.2.2.2(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5-9: foundation (3.5.1-29)	Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring. If a dewatering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes, if not within the scope of the Structures Monitoring Program, or a dewatering system is relied upon	Not applicable	Not applicable to Salem (see SER Sections 3.5.2.2.2(1) and 3.5.2.2.2(2))
Group 4: radial beam seats in BWR drywell; RPV support shoes for PWRs with nozzle supports; steam generator supports (3.5.1-30)	Lockup due to wear	ISI (IWF) or Structures Monitoring	Yes, if not within the scope of the Structures Monitoring Program	ASME Section XI, Subsection IWF	Consistent with the GALL Report (see SER Section 3.5.2.2.2(1))
Groups 1-3, 5, 7-9: below-grade concrete components, such as exterior walls below grade and foundation (3.5.1-31)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling), and aggressive chemical attack; cracking, loss of bond, loss of material (spalling, scaling), and corrosion of embedded steel	Structures Monitoring. Examination of representative samples of below-grade concrete and periodic monitoring of groundwater, if the environment is non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes, if environment is aggressive	Structures Monitoring Program and Buried Non-Steel Piping Inspection	Consistent with the GALL Report (see SER Sections 3.5.2.1.8 and 3.5.2.2.2(2))
Groups 1-3, 5, 7-9: exterior above- and below-grade reinforced concrete foundations (3.5.1-32)	Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide	Structures Monitoring for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if for inaccessible areas concrete was not constructed in accordance with ACI 201.2R-77	Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-5: concrete (3.5.1-33)	Reduction of strength and modulus due to elevated temperature	A plant-specific AMP is to be evaluated	Yes, if temperature limits are exceeded	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.2(3))
Group 6: concrete; all (3.5.1-34)	Increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack; cracking, loss of bond, and loss of material due to corrosion of embedded steel	Inspection of Water-Control Structures or Federal Energy Regulatory Commission (FERC)/U.S. Army Corps of Engineers dam inspections and maintenance programs and for inaccessible concrete, an examination of representative samples of below-grade concrete and periodic monitoring of groundwater, if the environment is non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes, if environment is aggressive	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants; Structures Monitoring Program; and Buried Non-Steel Piping Inspection	Consistent with the GALL Report (see SER Sections 3.5.2.1.8 and 3.5.2.2.2(4))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: exterior above- and below-grade concrete foundation (3.5.1-35)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes, for inaccessible areas located in moderate to severe weathering conditions	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(4))
Group 6: all accessible and inaccessible reinforced concrete (3.5.1-36)	Cracking due to expansion/ reaction with aggregates	For accessible areas, inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if for inaccessible areas concrete was not constructed in accordance with ACI 201.2R-77	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.2(4))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: exterior above- and below-grade reinforced concrete foundation interior slab (3.5.1-37)	Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide	For accessible areas, Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if for inaccessible areas concrete was not constructed in accordance with ACI 201.2R-77	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants; Structures Monitoring Program; and Open-Cycle Cooling Water System	Consistent with the GALL Report (see SER Sections 3.5.2.1.8 and 3.5.2.2.2(4))
Groups 7, 8: tank liners (3.5.1-38)	Cracking due to SCC; loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Salem (see SER Sections 3.5.2.1.1 and 3.5.2.2.2(5))
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-39)	Loss of material due to general and pitting corrosion	Structures Monitoring	Yes, if not within the scope of the Structures Monitoring Program	Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(6))
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-40)	Reduction in concrete anchor capacity due to local concrete degradation, service-induced cracking, or other concrete aging mechanisms	Structures Monitoring	Yes, if not within the scope of the Structures Monitoring Program	Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(6))
Vibration isolation elements (3.5.1-41)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, and sustained vibratory loading	Structures Monitoring	Yes, if not within the scope of the Structures Monitoring Program	Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2(6))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds (3.5.1-42)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to Salem (see SER Section 3.5.2.2.2(7))
Groups 1-3, 5, 6: all masonry block walls (3.5.1-43)	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Wall	No	Masonry Wall Program, Structures Monitoring Program, and Fire Protection	Consistent with the GALL Report
Group 6: elastomer seals, gaskets, and moisture barriers (3.5.1-44)	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Structures Monitoring	No	Structures Monitoring Program	Consistent with the GALL Report
Group 6: exterior above- and below-grade concrete foundation; interior slab (3.5.1-45)	Loss of material due to abrasion and cavitation	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants; Structures Monitoring Program; and Open-Cycle Cooling Water System	Consistent with the GALL Report (see SER Section 3.5.2.1.8)
Group 5: fuel pool liners (3.5.1-46)	Cracking due to SCC; loss of material due to pitting and crevice corrosion	Water Chemistry and monitoring of SFP water level in accordance with TSs and leakage from the leak chase channels.	No	Water Chemistry	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: all metal structural members (3.5.1-47)	Loss of material due to general (steel only), pitting, and crevice corrosion	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.1.5)
Group 6: earthen water control structures - dams, embankments, reservoirs, channels, canals, and ponds (3.5.1-48)	Loss of material and loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring Program	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-49)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and ISI (IWF)	No	Not applicable	Not applicable to Salem

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B2 and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-50)	Loss of material due to pitting and crevice corrosion	Structures Monitoring	No	Structures Monitoring Program; ASME Section XI, Subsection IWF; Periodic Inspection; RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants; Aboveground Non-Steel Tanks; and Bolting Integrity	Consistent with the GALL Report (see SER Sections 3.3.2.1.5, 3.5.2.1.2, and 3.5.2.1.5)
Group B1.1: high-strength, low-alloy bolts (3.5.1-51)	Cracking due to SCC and loss of material due to general corrosion	Bolting Integrity	No	ASME Section XI, Subsection IWF and Bolting Integrity	Consistent with the GALL Report (see SER Section 3.5.2.1.5
Groups B2 and B4: sliding support bearings and sliding support surfaces (3.5.1-52)	Loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads	Structures Monitoring	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report (see SER Section 3.5.2.1.6)
Groups B1.1, B1.2, and B1.3: support members: welds; bolted connections; support anchorage to building structure (3.5.1-53)	Loss of material due to general and pitting corrosion	ISI (IWF)	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers; guides; stops (3.5.1-54)	Loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Steel, galvanized steel, and aluminum support members; welds; bolted connections; support anchorage to building structure (3.5.1-55)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report
Groups B1.1, B1.2, and B1.3: sliding surfaces (3.5.1-56)	Loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Groups B1.1, B1.2, and B1.3: vibration isolation elements (3.5.1-57)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, and sustained vibratory loading	ISI (IWF)	No	Not applicable	Not applicable to Salem (see SER Section 3.5.2.1.1)
Galvanized steel and aluminum support members; welds; bolted connections; support anchorage to building structure exposed to air-indoor uncontrolled (3.5.1-58)	None	None	No	None	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-59)	None	None	No	None	Consistent with the GALL Report

The staff's review of the structures and component supports 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 component groups is documented in SER Section 3.0.3.

3.5.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the structures and structural components and their commodity groups:

- 10 CFR Part 50, Appendix J
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWF
- ASME Section XI, Subsection IWL
- Boric Acid Corrosion
- Buried Non-Steel Piping Inspection
- One-Time Inspection
- Periodic Inspection
- Protective Coating Monitoring and Maintenance Program
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Structures Monitoring Program
- TLAA
- Water Chemistry

Although not identified directly in LRA Section 3.5.2.1, LRA Table 3.5.1 identifies the following additional programs under the discussion column that manage aging effects for the structures, systems, or structural components and their commodity groups for specified conditions:

- Aboveground Non-Steel Tanks

- Bolting Integrity
- Fire Protection
- Masonry Wall Program
- Open-Cycle Cooling Water System

LRA Tables 3.5.2-1 through 3.5.2-17 summarize AMRs for the structures and component supports groups and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the report and for which it does not recommend further evaluation, the staff's audit and 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 line 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 line 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 reviewed these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line 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 reviewed these line 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 line 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 reviewed these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line 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 line 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 reviewed these line items to verify consistency with the GALL Report. The staff verified whether the AMR line 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 line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff reviewed these line 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.

LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-4, 3.5.2-5, 3.5.2-6, 3.5.2-7, 3.5.2-8, 3.5.2-10, 3.5.2-11, 3.5.2-12, 3.5.2-13, 3.5.2-15, 3.5.2-16, and 3.5.2-17 were revised as a result of the applicant's response, dated July 8, 2010, to RAI B.2.1.9-01. The revision added AMR items in these tables to reference the applicant's Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff notes that the Bolting Integrity Program is supplemented by other AMPs including but not limited to the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection programs. These other AMPs supplement the Bolting Integrity Program by implementing the requirements of the Bolting Integrity Program for pressure-retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action revised the LRA to add bolting component items in the tables mentioned above that are consistent with the GALL Report and have designated them as such with generic note B.

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 reviewed the LRA to confirm that the applicant: (1) provided a brief description of the system, components, materials, and environments; (2) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (3) identified those aging effects for the structures and structural components and their commodity groups that are subject to an AMR. On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1, the applicant's references to the GALL Report are acceptable and no further staff review is required, with the exception of the following AMRs that the applicant had identified were consistent with the AMRs of the GALL Report and for which the staff determined were in need of additional clarification and assessment. The staff's evaluations of these AMRs are provided in the subsections that follow.

3.5.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.5.1, item 3.5.1-5 addresses loss of material due to general, pitting, and crevice corrosion. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-7 addresses loss of prestress due to relaxation, shrinkage, creep, and elevated temperature. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR that incorporates a reinforced concrete containment and the AMR items in the GALL Report are only applicable to particular components of BWR designs that use a steel containment or containment designs that use a post-tensioning system. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs or post-tensioned concrete containments and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-8 addresses cumulative fatigue damage. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-11 addresses cracking due to SCC. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-13 addresses cracking due to cyclic loading. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-19 addresses cracking due to SCC. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-20 addresses loss of material due to general, pitting, and crevice corrosion. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-21 addresses fretting or lock up due to mechanical wear. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-22 addresses loss of material due to corrosion. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem is a PWR that incorporates a reinforced concrete containment and the AMR items in the GALL Report are only applicable to particular components of BWR designs that use a steel containment or containment designs that use a post-tensioning system. The staff verified that the stated AMR items in the GALL Report are only applicable to metallic components of BWR designs or post-tensioned concrete containments and are not applicable to the Salem LRA and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-38 addresses cracking due to SCC and loss of material due to pitting and crevice corrosion. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because Salem does not have Group 7 and 8 stainless steel tank liners. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any Group 7 and 8 stainless steel tank liners that are applicable for this line item and, therefore, finds the applicant's determination acceptable.

LRA Table 3.5.1, item 3.5.1-57 addresses reduction or loss of isolation function due to radiation hardening, temperature, humidity, and sustained vibratory loading. The applicant stated that the corresponding AMR items in the GALL Report are not applicable because the Salem design does not include vibration isolation elements in B1.1, B1.2, and B1.3 component supports. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any vibration isolation elements in B1.1, B1.2, and B1.3 component supports that are applicable for this line item and, therefore, finds the applicant's determination acceptable.

3.5.2.1.2 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1-50 addresses galvanized steel, aluminum, or stainless steel support members, welds, bolted connections, and support anchorage to building structures exposed to an outdoor air environment, which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Bolting Integrity Program to manage the aging effect for stainless steel bolting in the compressed air system (LRA Table 3.3.2-6). The GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E, which indicates that the LRA AMR is consistent with GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those line items associated with generic note E, GALL AMP XI.S6 recommends using visual inspections to manage the aging of these line items. In its review of components associated with item 3.5.1-50 for which the applicant cited generic note E, the staff noted that the Bolting Integrity Program proposes to manage the aging of galvanized stainless steel bolting through the use of visual inspections.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the Bolting Integrity Program provides visual examinations that are capable of detecting loss of material in bolted fasteners and includes provisions for appropriate corrective actions if indications of degradation are found. In its review of components associated with item 3.5.1-50, the staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because: (1) the focus of the program is aging management of bolting components, (2) the program includes visual examinations which have the capability to detect and correct loss of material in galvanized steel bolting if it should occur, and (3) the proposed inspection methods are consistent with the inspection methods in the GALL Report recommended AMP.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.3 Loss of Preload Due to Self-Loosening

In LRA Tables 3.5.2-1 through 3.5.2-8, 3.5.2-10 through 3.5.2-13, 3.5.2-16, and 3.5.2-17, for items that reference Table 3.3-1, item 3.3.1-45, the applicant included a reference to note E and credited the Structures Monitoring Program for managing this aging effect/mechanism in an indoor air environment for carbon and low-alloy steel bolting and galvanized steel bolting. The applicant also included plant-specific notes 1, 2, or 4 (depending on the table number).

Both plant-specific notes 1 and 2 state:

> Based on industry standards and operating experience[,] age related loss of preload/self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload/self-loosening of structural bolting is not significant and will not impact structural intended functions. Nevertheless, loss of preload/self-loosening will be monitored through the Structures Monitoring Program.

Plant-specific note 4 states, “[the] Structures Monitoring Program is the applicable aging management program for this component.” The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that referenced note E and plant-specific notes 1, 2, or 4. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, “Bolting Integrity,” the applicant has proposed using the Structures Monitoring Program.

The LRA states that these components have the intended function of structural support and are examined using the Structures Monitoring Program as the primary AMP. The staff’s review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant’s use of the Structures Monitoring Program acceptable because: (1) the Structures Monitoring Program monitors exposed surfaces of bolting for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload; (2) the program incorporates procedures based on EPRI TR-104213, “Bolted Joint Maintenance and Applications Guide,” to ensure proper specification of bolting material, lubricant, and installation torque; and (3) the Structures Monitoring Program supplements the Bolting Integrity Program as described in the applicant’s response to RAI B.2.1.9-01. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-2, for items that reference Table 3.3-1, item 3.3.1-45, the applicant included a reference to note E and credited the ASME Section XI, Subsection IWF Program for managing this aging effect/mechanism in an indoor air environment for carbon and low-alloy steel bolting. The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that referenced note E and plant-specific notes 1 and 2. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," the applicant has proposed using the ASME Section XI, Subsection IWF Program.

The LRA states that these components have the intended function of structural support and are examined using the ASME Section XI, Subsection IWF Program as the primary AMP. The staff's review of the ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's use of the ASME Section XI, Subsection IWF Program acceptable because: (1) the ASME Section XI, Subsection IWF Program provides periodic visual inspections of ASME Class 1, 2, and 3 piping and component support members for loss of material and loss of mechanical function, including inspection of bolting for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts and nuts; (2) the program relies on design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque; and (3) the ASME Section XI, Subsection IWF Program supplements the Bolting Integrity Program as described in the applicant's response to RAI B.2.1.9-01. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-3, for items that reference Table 3.2-1, item 3.2.1-24, the applicant included a reference to note E and credited the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs for managing this aging effect/mechanism in an indoor air environment for carbon and low-alloy steel bolting. The applicant also included plant-specific note 1 which states, "ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J are the applicable aging management program for this component." The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that referenced note E and plant-specific note 1. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," the applicant has proposed using the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs.

The LRA states that these components have the intended function of pressure boundary and that the 10 CFR Part 50, Appendix J and ASME Section XI, Subsection IWE programs have been substituted to manage loss of preload due to self-loosening in steel bolting exposed to indoor air. The staff's evaluations of the applicant's 10 CFR Part 50, Appendix J and ASME Section XI, Subsection IWE programs are documented in SER Sections 3.0.3.1.18 and 3.0.3.2.13, respectively. The staff finds the applicant's use of the 10 CFR Part 50, Appendix J and ASME Section XI, Subsection IWE programs acceptable because: (1) the 10 CFR Part 50, Appendix J Program provides for detection of age-related degradation of components comprising the containment pressure boundary; (2) the ASME Section XI, Subsection IWE Program conducts general and detailed visual examinations and augmented inspections for evidence of aging effects that could affect leak tightness of the containment structure and includes the pressure-retaining bolting; and (3) the 10 CFR Part 50, Appendix J Program and the ASME Section XI, Subsection IWE Program supplements the Bolting Integrity Program as described in the applicant's response to RAI B.2.1.9-01. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.4 Increased Hardness, Shrinkage, and Loss of Strength Due to Weathering

In LRA Tables 3.5.2-1, 3.5.2-3, 3.5.2-5, and 3.5.2-7, for items that reference Table 3.3-1, item 3.3.1-61, the applicant included a reference to note E and credited the Structures Monitoring Program for managing this aging effect/mechanism in an indoor or outdoor environment for elastomers. The applicant also included plant-specific notes 2, 3, or 4 (depending on the table number) which each state, "[The] Structures Monitoring Program is the applicable aging management program for this component." The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that referenced note E and plant-specific notes 2, 3, or 4. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M26, "Fire Protection," the applicant has proposed using the Structures Monitoring Program. In the LRA, it states that this line item relates to compressible joints and seals (seismic gap) and provides an intended function of expansion/separation.

The LRA states that these components are examined using the Structures Monitoring Program as the primary AMP. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's use of the Structures Monitoring Program acceptable because: (1) the Structures Monitoring Program has been enhanced to visually inspect elastomers for hardening, shrinkage, and loss of sealing; (2) the intended function of the elastomers is to provide expansion/separation in seismic gaps; and (3) the LRA does not list an intended function of the elastomers as fire barriers. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-13, for items that reference Table 3.3-1, item 3.3.1-61, the applicant included a reference to note E and credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing this aging effect/mechanism in an air-outdoor environment for elastomers. The applicant also included plant-specific note 2 which states, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, is the applicable aging management program for this environment and aging effect/mechanism combination for this component." The LRA states that this line item relates to the ice barrier, marine dock bumper and provides an intended function of shelter/protection in the service water intake system. The applicant stated that components have been aligned to this item number based on material, environment, and aging effect

The staff reviewed the AMR results lines that referenced note E and plant-specific note 2. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M26, "Fire Protection," the applicant has proposed using the

RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.

The LRA states that these components have the intended function of shelter/protection in the form of elastomers for the ice barrier, marine dock bumper and are examined using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as the primary AMP. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented through the applicant's Structures Monitoring Program. The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and the Structures Monitoring programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.15, respectively. The staff finds the applicant's use of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because: (1) the program has been enhanced to visually inspect elastomers for hardening, shrinkage, and loss of strength due to weathering and elastomer degradation; (2) the program is implemented through the Structures Monitoring Program that conducts visual inspections on a frequency not to exceed 5 years; and (3) the LRA does not list an intended function of the elastomers as fire barriers. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-13, for items that reference Table 3.3-1, item 3.3.1-75, the applicant included a reference to note E and credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing this aging effect/mechanism in a water-flowing environment for elastomers. The applicant also included plant-specific note 2 which states, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, is the applicable aging management program for this environment and aging effect/mechanism combination for this component." The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that referenced note E and plant-specific note 2. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," the applicant has proposed using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.

The LRA states that these components associated with the service water intake system have the intended function of shelter/protection in the form of elastomers for the ice barrier, marine dock bumper and are examined using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as the primary AMP. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented through the applicant's Structures Monitoring Program. The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and the Structures Monitoring programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.15, respectively. The staff finds the applicant's use of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because: (1) the program has been enhanced to visually inspect elastomers for hardening, shrinkage, and loss of strength due to weathering and elastomer degradation; (2) the program is implemented through the Structures Monitoring Program that conducts visual inspections on a frequency not to exceed 5 years; and (3) GALL AMP XI.M20 is intended to address aging effects of material loss and fouling due to micro- and macro-organisms and various corrosion mechanisms. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

In LRA Tables 3.5.2-1, 3.5.2-3, and 3.5.2-13, for items that reference Table 3.3-1, item 3.3.1-80, the applicant included a reference to note E and credited the Structures Monitoring Program for managing this aging effect/mechanism for stainless steel material in a raw water environment.

The staff reviewed the AMR results lines that referenced note E and plant-specific notes 1 and 4. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," the applicant has proposed using the Structures Monitoring Program.

The LRA states that the stainless steel sump screen trench cover, sump liner, liner/liner anchors/integral attachments, or vortex suppressors have intended functions of either structural support, water-retaining boundary, filter, or direct flow and are examined using the Structures Monitoring Program. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's use of the Structures Monitoring Program acceptable because the program: (1) performs visual inspections to monitor for indications of degradation; (2) implements the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program; and (3) has been enhanced to conduct the visual inspections on a frequency not to exceed 5 years. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-13, for items that reference Table 3.3-1, item 3.3.1-80, the applicant included a reference to note E and credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing this aging effect/mechanism in a raw water environment for stainless steel bolting or stainless steel concrete anchors having an intended function of structural support. The applicant also included plant-specific note 2 which states, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, is an appropriate AMP for environment and aging effect/mechanism combination for this component."

The staff reviewed the AMR results lines that referenced note E and plant-specific note 2. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," the applicant has proposed using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.

The LRA states that the stainless steel structural bolting and stainless steel concrete anchors have an intended function of structural support and are examined using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. 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 3.0.3.2.16. The staff finds the applicant's use of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because the program: (1) is based on guidance provided in RG 1.127 and ACI 349.3R, (2) performs visual inspections, (3) is implemented through the Structures Monitoring Program to monitor for indications of degradation, and (4) has been enhanced to conduct the visual inspections on a frequency not to exceed 5 years. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-3, for items that reference Table 3.4-1, item 3.4.1-33, the applicant included a reference to note E and credited the Periodic Inspection Program for managing this aging effect/mechanism in a raw water environment for stainless steel material having an intended function of filter. The applicant also included plant-specific note 12 which states that periodic Inspection is the applicable AMP for this component.

The staff reviewed the AMR results lines that referenced note E and plant-specific note 12. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," the applicant has proposed using the Periodic Inspection Program.

The LRA states that the stainless steel sump screen has an intended function of filter and is examined using the Periodic Inspection Program. The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The Periodic Inspection Program is a condition monitoring program that includes provisions for periodic visual inspections of stainless steel components in a raw water environment to detect loss of material and the presence and extent of fouling that could result in reduction of heat transfer. The applicant noted that the inspection frequency is established based on plant and industry operating experience and for stainless steel components subject to a raw water environment, operating experience indicates that a 10-year inspection frequency will be adequate to detect loss of material prior to loss of component intended function. The staff agrees that the Periodic Inspection Program is an appropriate AMP to address this AERM, however, since the GALL AMP XI.M20 inspections are done annually and during refueling outages, it is unclear to the staff that an inspection interval of 10 years will be adequate to address the AERM. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-03 to address this issue.

In its response dated July 8, 2010, the applicant stated that components in the containment structure were aligned to GALL Report item 3.4.1-33 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination. The applicant further stated that the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report and that the recommended GALL Report programs are not applicable for aging management of the containment sump screens. The applicant also stated that the sump screens are not located within the sump pit and are not normally exposed to raw water; therefore, raw water is deleted as an environment for the containment sump screens. The applicant further stated that the screens may be exposed to air with untreated steam or water leakage so an AMR line item was included in the original application to address this environment.

The staff reviewed the applicant's response and found it acceptable because it explains that the components are not exposed to a raw water environment and it removes the corresponding AMR line item from the application. The staff's evaluation of aging management of screens in an air with untreated steam or water leakage environment is addressed in SER Section 3.5.2.3.3. Based on its review of the applicant's response, the staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.1-03 is resolved.

In LRA Tables 3.2.2-3, 3.3.2-2, and 3.4.2-1, for items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to note E and credited the Aboveground Non-Steel Tanks Program for managing loss of material due to pitting and crevice corrosion in an air-outdoor environment for stainless steel components.

The staff reviewed the AMR lines that reference note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the Aboveground Non-Steel Tanks Program.

The staff's evaluation of the applicant's Aboveground Non-Steel Tanks Program is documented in SER Section 3.0.3.3.3. The staff noted that the Aboveground Non-Steel Tanks Program performs visual inspections to monitor for indications of degradation at a frequency of 5 years or less. GALL AMP XI.S6 recommends visual inspections at a frequency of 5 years or less for components exposed to an exterior environment. The staff finds the applicant's use of the Aboveground Non-Steel Tanks Program acceptable because the applicant's credited program performs inspections which are equivalent to the GALL Report recommended program. The staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-2, for items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to note E and credited the ASME Section XI, Subsection IWF Program for managing this aging effect/mechanism in an air-outdoor environment for stainless steel material having an intended function of structural support. The applicant also included plant-specific note 1 which states, "ASME Section XI, Subsection IWF is the applicable aging management program for this component." The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that referenced note E and plant-specific note 1. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the ASME Section XI, Subsection IWF Program.

The LRA states that the stainless steel supports for ASME Class 2 and 3 piping and supports have an intended function of structural support and are examined under the ASME Section XI, Subsection IWF Program. The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's use of the ASME Section XI, Subsection IWF Program acceptable because the program: (1) provides periodic visual inspections of ASME Class 1, 2, and 3 piping and component support members for loss of material and loss of mechanical function, including inspection of bolting for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts and nuts and (2) relies on design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In the LRA line items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to note E and credited the Periodic Inspection Program for managing this aging effect/mechanism in an air-outdoor environment for aluminum and stainless steel materials.

The staff reviewed the AMR results lines that referenced note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, “Structures Monitoring Program,” the applicant has proposed using the Periodic Inspection Program.

The LRA states that the Periodic Inspection Program is a condition monitoring program that manages aging of piping, piping components, piping elements, ducting components, tanks, and heat exchanger components and includes provisions for periodic visual inspections of aluminum components to detect loss of material aging effects. The staff’s evaluation of the applicant’s Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The LRA also states that the visual inspections are conducted on a 10-year inspection frequency that has been established based on plant and industry operating experience. The staff notes that the applicant’s Periodic Inspection Program does not appear to address the aluminum and stainless steel insulation jacketing and for components located in an air-outdoor environment, does not meet guidance such as that provided in ACI 349.3R as referenced by GALL AMP XI.S6, which recommends an inspection frequency of 5 years for this environment. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-04 to address this issue.

In its response dated July 8, 2010, the applicant stated that the aluminum and stainless steel components were aligned to GALL Report item 3.3.1-50 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination; the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report and that the recommended GALL Report programs are not applicable for aging management of the components. The applicant further explained that the Periodic Inspection Program is the appropriate program to manage these components and the program includes all the referenced items within its scope. The applicant explained that the 10-year inspection frequency is appropriate for stainless steel and aluminum components exposed to outdoor air due to the corrosion resistance of the materials. The applicant explained that this conclusion was supported by plant-specific operating experience, including inspections of outdoor stainless steel piping in 2002, 2006, and 2008 which showed no signs of age-related degradation. These inspections suggest little to no age-related degradation after 30 years in service and suggest that corrosive contamination is not an issue in the Salem air-outdoor environment.

The staff reviewed the applicant’s response and noted that all of the AMR line items in question are included within the scope of the applicant’s Periodic Inspection Program. The staff also noted that the applicant provided justification for the 10-year inspection interval, based on plant-specific operating experience. Based on its review, the staff finds the applicant’s use of the Periodic Inspection Program acceptable because it includes appropriate visual inspections at an appropriate frequency to detect degradation of aluminum and stainless steel components exposed to an air-outdoor environment. The staff finds that the applicant addressed the AERM adequately and the staff’s concern in RAI 3.5.2.1-3 is resolved.

In LRA Table 3.5.2-13, for items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to note E and credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing this aging effect/mechanism in an air-outdoor environment for stainless steel bolting and concrete anchors having an intended function of structural support for the service water intake. The applicant also included plant-specific note 2 which states, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, is the applicable aging management program for this component."

The staff reviewed the AMR results lines that referenced note E and plant-specific note 2. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.

The LRA states that the stainless steel bolting and concrete anchors are examined under the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. 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 3.0.3.2.16. The LRA also states that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented through the applicant's Structures Monitoring Program. The staff finds the applicant's use of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because the program: (1) is implemented through the Structures Monitoring Program, (2) includes provisions to monitor for indications of degradation, and (3) has been enhanced to conduct visual inspections on a frequency not to exceed 5 years. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-17, for items that reference Table 3.5-1, item 3.5.1-47, the applicant included a reference to note E and credited the Structures Monitoring Program for managing this aging effect/mechanism in an air-outdoor environment for cast iron hatches/plugs (manhole/manhole covers) having an intended function of structural support for the yard structures. The applicant also included plant-specific note 3 which states, "Water control structures are monitored in accordance with the Structures Monitoring Program, which includes the ten attributes of NUREG-1801 Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (XI.S7)."

The staff reviewed the AMR results lines that referenced note E and plant-specific note 3. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," the applicant has proposed using the Structures Monitoring Program.

The LRA states that the cast iron hatches/plugs are examined under the Structures Monitoring Program under which the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented. The staff's evaluations of the applicant's Structures Monitoring Program and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program are documented in SER Sections 3.0.3.2.15

and 3.0.3.2.16, respectively. Although the GALL Report line item addresses metal (steel) components, cast iron is an alloy of iron having a higher carbon content that makes it more resistant to corrosion than steel. The staff finds the applicant's use of the Structures Monitoring Program acceptable because the program: (1) implements the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, (2) performs visual inspections to monitor for indications of degradation, and (3) has been enhanced to conduct the visual inspections on a frequency not to exceed 5 years. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.5.2-2, for items that reference Table 3.5-1, item 3.5.1-51, the applicant included a reference to note E and credited the ASME Section XI, Subsection IWF Program for managing this aging effect/mechanism in an indoor air environment for high-strength, low-alloy steel bolting with a yield strength greater than 150 ksi and having an intended function of structural support for Class 1 piping and components (high-strength bolting for NSSS component supports). The applicant also included plant-specific notes 1, 5, and 6 in LRA Table 3.5.2-2. Plant-specific note 1 states, "ASME Section XI, Subsection IWF is the applicable aging management program for this component." Plant-specific note 5 states:

> Supports for the Reactor Coolant Pumps and Unit 1 SGs have high strength maraging steel bolts (Vascomax 200, 300) with actual yield strength greater than 150 ksi. The bolts are not preloaded (not torqued) and are not subject to high tensile stress or a corrosive environment. A review of plant operating experience has not identified any instances of SCC for the bolts. Therefore, cracking due to stress corrosion cracking is not an aging effect requiring aging management. Loss of material is the only aging effect requiring aging management.

Plant-specific note 6 states, "Loss of preload/self-loosening is not applicable because the bolts are not required to be preloaded by design. Also, the bolt nuts are either tack welded or lock wired to prevent undesirable self-loosening."

The staff reviewed the AMR results lines that referenced note E and plant-specific notes 1, 5, and 6. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," the applicant has proposed using the ASME Section XI, Subsection IWF Program.

The LRA states that these components have the intended function of structural support and are examined using the ASME Section XI, Subsection IWF Program as the primary AMP. The staff's review of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.17. The staff finds the applicant's use of the ASME Section XI, Subsection IWF Program acceptable because: (1) the program performs periodic visual examinations of exposed surfaces of bolting used in supports for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts and nuts, including monitoring for loss of material due to general corrosion of high-strength bolts (actual yield strength greater than 150 ksi) used in NSSS component supports; (2) the bolts are in an indoor air, non-corrosive environment; (3) the bolts are not preloaded and are either tack welded or lock wired to prevent undesirable self-loosening; and (4) the program incorporates procedures based on EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.6 Loss of Mechanical Function Due to Corrosion, Distortion, Dirt, and Overload and Fatigue Due to Vibratory and Cyclic Thermal Loads

In LRA Table 3.5.2-2, for items that reference Table 3.5-1, item 3.5.1-52, the applicant included a reference to note E and credited the ASME Section XI, Subsection IWF Program for managing this aging effect/mechanism in an indoor environment for Graph-Air tool steel having an intended function of structural support for Class 1 piping and components (sliding surfaces-NSSS component supports). The applicant also included plant-specific note 1 which states, "ASME Section XI, Subsection IWF is the applicable aging management program for this component."

The staff reviewed the AMR results lines that referenced note E and plant-specific note 1. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the ASME Section XI, Subsection IWF Program.

The LRA states that these components have the intended function of structural support and are examined using the ASME Section XI, Subsection IWF Program as the primary AMP. The staff's review of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.17. The GALL Report recommends no further evaluation for lockup of sliding surfaces if the Structures Monitoring Program is used to manage aging. In its review, the staff noted that the applicant is not using the Structures Monitoring Program as the AMP and the staff was unable to verify that these sliding support surfaces were being inspected for loss of mechanical function due to corrosion, distortion, dirt, and overload, or fatigue due to vibratory and cyclic thermal loads under the ASME Section XI, Subsection IWF Program. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-05 to address this issue.

In its response dated July 8, 2010, the applicant stated that the Graph-Air tool steel components were aligned to GALL Report item 3.5.1-52 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination; however, the ASME Section XI, Subsection IWF Program was credited because the components are ASME Code Section XI Class 1 component supports. The applicant also stated that the ASME Section XI, Subsection IWF Program requires visual examinations to detect loss of mechanical function, regardless of the specific aging mechanism.

The staff reviewed the applicant's response and noted that the scope of the ASME Section XI, Subsection IWF Program includes the Graph-Air tool steel components, as well as the aging effect of loss of mechanical function. The applicant also explained that the ASME Section XI, Subsection IWF Program was the appropriate AMP because the components are ASME Code Section XI Class 1 supports. Based on its review, the staff finds the applicant's use of the

ASME Section XI, Subsection IWF Program acceptable because it includes appropriate visual inspections at an appropriate frequency to detect degradation of sliding supports. The staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.1-05 is resolved.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.7 Cracks and Distortion Due to Increased Stress Levels from Settlement

In LRA Table 3.5.2-3, for items that reference Table 3.5-1, item 3.5.1-2, the applicant included a reference to note E and credited the ASME Section XI, Subsection IWL Program for managing this aging effect/mechanism for reinforced concrete in an air-outdoor or indoor air environment. The applicant also included plant-specific note 5 in LRA Table 3.5.2-3, which states, "ASME Section XI, Subsection IWL is the applicable aging management program for this component."

The staff reviewed the AMR results lines that referenced note E and plant-specific note 5. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the ASME Section XI, Subsection IWL Program.

The LRA states that these components have intended functions of either flood barrier, missile barrier, pressure boundary, shelter/protection, shielding, or structural support and are monitored by the ASME Section XI, Subsection IWL Program. The staff's review of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.1.16. The staff finds the applicant's use of the ASME Section XI, Subsection IWL Program acceptable because: (1) the program conducts general visual examinations of accessible surfaces to detect degradation and distress such as defined in ACI 201.1, including loss of material, cracks and distortion, and loss of bond; (2) detailed visual examinations are conducted on concrete surfaces that are suspect to determine the magnitude and extent of deterioration and distress; (3) acceptance criteria are based on ACI 349.3R guidance; and (4) the LRA states that neither a dewatering system nor porous concrete subfoundation exist at Salem. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Table 3.3.2-12, for items that reference Table 3.5-1, item 3.5.1-28, the applicant included a reference to note E and credited the Fire Protection Program for managing this aging effect/mechanism in an outdoor or indoor air environment. The applicant also included plant-specific note 3 which states, "The Fire Protection aging management program will be used in addition to the Structures Monitoring Program."

The staff reviewed the AMR results lines that reference note E and plant-specific note 6. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the Fire Protection Program in addition to the Structures Monitoring Program.

The LRA states that these components have the intended function of fire barriers and are examined using the Structures Monitoring Program in addition to the Fire Protection Program as the AMPs. The staff's evaluations of the applicant's Structures Monitoring and Fire Protection programs are documented in SER Sections 3.0.3.2.15 and 3.0.3.2.5, respectively. The staff finds the applicant's use of the Fire Protection and Structures Monitoring programs acceptable because: (1) the Fire Protection Program has been enhanced to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material; and (2) the walls are also inspected under the Structures Monitoring Program, which implements the applicant's Masonry Wall Program. The staff finds that the applicant addressed the AERM adequately.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.8 Increase of Porosity and Permeability, Loss of Strength Due to Leaching of Calcium Hydroxide, and Loss of Material Due to Abrasion and Cavitation

In LRA Tables 3.3.2-4 and 3.3.2-23, for items that reference Table 3.5-1, items 3.5.1-31 and 3.5.1-34, the applicant included a reference to note E and credited the Buried Non-Steel Piping Inspection Program for managing these aging effect/mechanisms in a groundwater/soil (external) environment. The applicant also included plant-specific note 2 or 10 (depending on the table) which states, "The Buried Non-Steel Piping Inspection program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination."

The staff reviewed the AMR results lines that reference note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," and GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," the applicant has proposed using the Buried Non-Steel Piping Inspection Program.

The LRA states that these reinforced concrete piping and fitting components have the intended function of pressure boundary and are examined using the Buried Non-Steel Piping Inspection Program. The staff's evaluation of the applicant's Buried Non-Steel Piping Inspection Program is documented in SER Section 3.0.3.3.4. Given that there have been a number of recent industry events involving leakage from buried or underground piping, the staff needs further information to evaluate the impact that these recent industry events might have on the applicant's Buried Non-Steel Piping Inspection Program. By letter dated August 6, 2010, the staff issued RAI B.2.1.22 requesting that the applicant provide information regarding how Salem will incorporate the recent industry operating experience into its AMRs and AMPs. The staff reviewed the RAI response received on September 7, 2010, and sent a follow-up RAI on October 18, 2010, requesting additional information. By letter dated November 10, 2010, the applicant responded and stated that at least 8 linear feet of buried reinforced concrete piping will be inspected prior to the period of extended operation, and then at least once in every 10 year period during the period of extended operation. The response and the staff's review are discussed in more detail in the Buried Non-Steel Piping Inspection Program review documented in SER Section 3.0.3.3.4.

Based on the response, the staff finds the applicant's aging management approach acceptable for buried concrete piping because the applicant: (1) has no operating experience with leakage from non-steel piping and (2) will conduct visual inspections on the piping at least once every 10 years. This inspection method and frequency aligns with the recommendation in ACI 349.3R, which is an acceptable method for fulfilling the recommendations of the GALL Report.

In LRA Table 3.5.2-5, for items that reference Table 3.5-1, items 3.5.1-37 and 3.5.1-45, the applicant included a reference to note E and credited the Structures Monitoring Program for managing this aging effect/mechanism for reinforced concrete in a flowing water environment. The applicant also included plant-specific note 2 in LRA Table 3.5.2-5, which states, "[The] Structures Monitoring Program is the applicable aging management program for this component."

The staff reviewed the AMR results lines that referenced note E and plant-specific note 2. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs, the applicant has proposed using the Structures Monitoring Program. The LRA also states that this component is an interior trench constructed of reinforced concrete and has the intended function of directing flow of water.

The LRA states that the applicant's Structures Monitoring Program is used to implement the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff's review of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff noted that the component in question is an internal concrete structure, so the Structures Monitoring Program would be the appropriate AMP to address aging of this component. The staff finds the applicant's use of the Structures Monitoring Program acceptable because the program: (1) conducts visual inspections on a frequency not to exceed 5 years and (2) is based on guidance provided in RG 1.127 and ACI 349.3R. Since the applicant has committed to an appropriate AMP for the period of extended operation, the staff finds that the applicant addressed the AERM adequately.

In LRA Tables 3.3.2-4 and 3.3.2-23, for items that reference Table 3.5-1, items 3.5.1-37 and 3.5.1-45, the applicant included a reference to note E for both items and credited the Open-Cycle Cooling Water System Program for managing these aging effect/mechanisms in a raw water (internal) environment. The applicant also included plant-specific note 3 or 11 (LRA Table 3.3.2-4 and 3.3.2-23, respectively) which states, "The Open-Cycle Cooling Water System program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination."

The staff reviewed the AMR results lines that reference note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," the applicant has proposed using the Open-Cycle Cooling Water System Program.

The staff noted that these reinforced concrete piping and fitting components have the intended function of pressure boundary and are examined using the Open-Cycle Cooling Water System Program. The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. The staff also noted that the applicant's Open-Cycle Cooling Water System Program includes activities to manage internal degradation of piping, including cracking, loss of material, and increase in porosity and permeability. In addition, the concrete piping within scope of this program has a polymer coating applied to the interior surface of the pipe and the interior of each piping header is visually inspected every other refueling outage for signs of coating and concrete degradation. Visual inspections of the piping header will detect indications of age-related degradation in the piping, and the header condition should be representative of the main piping. The type and frequency of the inspections are appropriate based on guidance provided by other GALL Report programs which manage aging of concrete, such as the Structures Monitoring Program. These programs suggest visual inspections with a frequency of at least every 5 years to detect degradation of concrete exposed to raw water. Based on its review, the staff finds that the applicant addressed the AERM adequately.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.9 Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel and Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw

In LRA Table 3.3.2-12, for items that reference Table 3.5-1, item 3.5.1-23 or 3.5.1-26, the applicant included a reference to note E and credited the Fire Protection Program for managing this aging effect/mechanism in an air-outdoor or indoor air environment. The applicant also included plant-specific note 3 which states, "The Fire Protection aging management program will be used in addition to the Structures Monitoring Program."

The staff reviewed the AMR results lines that reference note E and plant-specific note 3 in LRA Table 3.3.2-12. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring Program," the applicant has proposed using the Fire Protection Program in addition to the Structures Monitoring Program.

The LRA states that these components have the intended function of fire barriers and are examined using the Structures Monitoring Program in addition to the Fire Protection Program as the AMPs. The staff's evaluations of the applicant's Structures Monitoring and Fire Protection programs are documented in SER Sections 3.0.3.2.15 and 3.0.3.2.5, respectively. The staff finds the applicant's use of the Fire Protection and Structures Monitoring programs acceptable because: (1) the Fire Protection Program has been enhanced to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material and (2) the walls are also inspected under the Structures Monitoring Program, which implements the Masonry Wall Program. The staff finds that the applicant addressed the AERM adequately.

Based on a review of the programs identified above, the staff determines that the applicant's proposed programs are acceptable for managing the aging effects in the applicable components. 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).

3.5.2.1.10 Conclusion for AMRs Consistent with the GALL Report

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated 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 with the GALL Report AMRs. Therefore, the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

In LRA Section 3.5.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the containments, structures, and component supports components and provides information concerning how it will manage aging effects in the following three areas:

(1) PWR containments:

- aging of inaccessible concrete areas
- cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations if not covered by the Structures Monitoring Program
- reduction of strength and modulus of concrete structures 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
- cracking due to cyclic loading
- loss of material (scaling, cracking, and spalling) due to freeze-thaw

- cracking due to expansion and reaction with aggregates and increase in porosity and permeability due to leaching of calcium hydroxide

(2) safety-related and other structures and component supports:

- aging of structures not covered by the Structures Monitoring Program
- aging management of inaccessible areas (below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures)
- reduction of strength and modulus of concrete structures due to elevated temperature for Groups 1–5 structures
- aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas)
- cracking due to SCC and loss of material due to pitting and crevice corrosion for Groups 7 and 8 stainless steel tank liners
- aging of supports not covered by the Structures Monitoring Program
- cumulative fatigue damage due to cyclic loading

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff 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 Pressurized Water Reactor and Boiling Water Reactor Containments

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1.

Aging of Inaccessible Concrete Areas. LRA Section 3.5.2.2.1.1 addresses aging of inaccessible concrete areas. In the LRA, the applicant stated that the ASME Section XI, Subsection IWL Program and the Structures Monitoring Program will be used to manage aging of accessible and inaccessible containment structure concrete elements, respectively, for increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel. In the LRA, the applicant stated that: (1) the containment structure was designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66; (2) the Type II Portland cement conformed to ASTM C-150; (3) fly ash was used in the concrete mixtures; and (4) concrete aggregates conformed to the requirements of ASTM C 33-66 and were tested in accordance with ASTM Specifications C29-60, C40-66, C127-59, C128-59, and C88-63 and ASTM Specification C289-65 for potential reactivity. The applicant also stated that a review of operating experience has not indicated any significant signs of distress due to aggressive chemical attack or corrosion of embedded steel of submerged concrete components, although the chloride levels on the site are considered aggressive (greater than 500 ppm).

The staff reviewed LRA Section 3.5.2.2.1.1 against the criteria in SRP-LR Section 3.5.2.2.1.1, which state that increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in inaccessible areas of PWR and BWR concrete and steel containments. The GALL Report identifies GALL AMP XI.S2, "ASME Section XI, Subsection IWL," to manage these aging effects and recommends further evaluation of plant-specific programs to manage these aging effects for inaccessible areas if the environment is aggressive.

The staff confirmed that aging management of all accessible areas of the concrete containment building for cracking, loss of material, and increase in porosity and permeability is managed by the ASME Section XI, Subsection IWL Program. The staff's evaluation of the ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.1.16. SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas," documents the staff's review of the applicant's evaluation of aging management of inaccessible areas, including the containment-related concrete.

<u>Cracks and Distortion Due to Increased Stress Levels from Settlement and Reduction of Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, if Not Covered by the Structures Monitoring Program</u>. LRA Section 3.5.2.2.1.2 addresses cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations, if not covered by the Structures Monitoring Program. In the LRA, the applicant stated that settlement measurements were made throughout plant construction and during initial operation and indicated a maximum settlement of approximately 12.7 millimeters (0.5 inches) and that this item is not applicable because the concrete components are evaluated under the Structures Monitoring Program and no permanent dewatering system or porous concrete foundations exist at Salem.

The staff reviewed LRA Section 3.5.2.2.1.2 against the criteria in SRP-LR Section 3.5.2.2.1.2, which state that cracks and distortion due to increased stress levels from settlement and reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur. The GALL Report identifies GALL AMP XI.S6, "Structures Monitoring Program," to manage these aging effects and no further evaluation is recommended if this activity is within scope of the Structures Monitoring Program.

The staff confirmed that structures and structural components at Salem are inspected under the Structures Monitoring Program for indications of deterioration such as defined in ACI 201.1R and that the program has been enhanced to include additional acceptance criteria specified in ACI 349.3R-96, which would capture degradation due to differential settlement. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff also confirmed that no permanent dewatering system or porous concrete foundations exist at Salem. The staff finds the applicant's evaluation of this AERM acceptable in that the criteria in SRP-LR Section 3.5.2.2.1.2 are met.

<u>Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. LRA Section 3.5.2.2.1.3 addresses reduction of strength and modulus of concrete structures due to elevated temperature. In the LRA, the applicant stated that this item number is not applicable at

Salem. The containment structure concrete is not exposed to general temperatures greater than 65 °C (150 °F) or local area temperature greater than 93 °C (200 °F). Salem TS 3 /4.6.1.5 limits the average air temperature inside the containment during normal plant operation to 49 °C (120 °F). The bulk air temperature is maintained within the TS limits by recirculating air through cooling coils. High temperature process piping penetrations in the containment wall are insulated and provided with a cooling system to limit concrete temperature to a maximum of 65 °C (150 °F). No portion of the concrete containment components exceeds the specified temperature limits.

The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3, which recommends further evaluation of the plant-specific AMP if any portion of the concrete containment components exceeds the specified temperature limits of 65 °C (150 °F) general and 93 °C (200 °F) local.

The staff finds the applicant's evaluation acceptable that this aging effect is not applicable because Salem containment concrete remains below the GALL Report specified temperature limits. SER Section 3.5.2.2.2, "Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature," documents the staff's review of the applicant's evaluation of aging management for reduction of strength and modulus of other in-scope concrete structures due to elevated temperature.

<u>Loss of Material Due to General, Pitting, and Crevice Corrosion</u>. LRA Section 3.5.2.2.1.4 addresses loss of material due to general, pitting, and crevice corrosion for steel elements of accessible and inaccessible areas of containments. In the LRA, the applicant stated that the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs will be used to manage aging of accessible and inaccessible areas of the containment structure steel elements due to general, pitting, and crevice corrosion. The applicant further stated that visual and UT examinations of the containment liner conducted in accordance with ASME Code Section XI, Subsection IWE have not identified significant loss of material due to corrosion. Also, the conditions established in the GALL Report are met and thus, a further evaluation of plant-specific AMPs is not required for managing loss of material due corrosion in inaccessible areas of the containment structure steel elements. The concrete in accessible interior areas of the containment structure is monitored by the Structures Monitoring Program to ensure penetrating cracks that could provide a path for water seepage to the surface of the containment liner, if identified, are entered into the corrective action program and accepted by evaluation or repaired. The applicant also explained that the lower portion of the containment steel liner is largely covered by the liner insulation and stainless steel lagging, causing portions of the liner to be considered inaccessible in accordance with ASME Code Section XI, Subsection IWE-1232. Thus, only the portions of the steel liner that are accessible are inspected by general visual examination in accordance with ASME Code Section XI, Subsection IWE. In the LRA, the applicant explained that the inaccessible steel liner areas are accepted based on the condition of adjacent accessible areas. The applicant also explained that visual inspection of 100 percent of the moisture barrier, at the junction between the containment concrete floor and the containment liner, will be performed in accordance with ASME Code Section XI, Subsection IWE program requirements, to the extent practical, within the limitation of design, geometry, and materials of construction of the components. The bottom edge of the stainless steel insulation lagging will be trimmed, if necessary, to perform the moisture barrier inspections. The applicant further stated that borated water leakage is monitored in accordance with the Boric Acid Corrosion Program. In the LRA, the applicant stated that inspections conducted in accordance with ASME Code Section XI, Subsection IWE and testing in accordance with 10 CFR Part 50, Appendix J will provide reasonable assurance that loss of

material due to corrosion in accessible and inaccessible areas of the containment structure will be detected prior to a loss of intended function.

The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4, which state that loss of material due to general, pitting, and crevice corrosion could occur in steel elements of accessible and inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J to manage this aging effect. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if corrosion is significant. GALL Report item II.A1-11 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 Code Section XI, Subsection IWE requirements.

(4) Water ponding on the containment concrete floor is not common and when detected is cleaned up in a timely manner.

The staff's evaluations of the applicant's Structures Monitoring Program; ASME Section XI, Subsection IWE Program; and 10 CFR Part 50, Appendix J Program are documented in SER Sections 3.0.3.2.15, 3.0.3.2.13, and 3.0.3.1.18, respectively. The staff found that conditions two, three, and four were adequately addressed; however, the LRA did not discuss condition one adequately in that it was not specified how guidance contained in ACI 201.2R as specified in GALL Report item II.A1-11 was met. By letter dated June 7, 2010, the staff issued RAI 3.5.2.2.1-01 requesting that the applicant discuss how the concrete in contact with the embedded steel liner complies with the guidance in ACI 201.2R.

In its response dated July 8, 2010, the applicant stated that containment concrete meets the guidance in ACI 201.2R related to low permeability concrete and limiting chlorides in the concrete mix. The applicant explained that the concrete mix design provided for low permeability concrete and included fly ash, while the chlorides were limited in the concrete mix and the mixing water. The applicant further stated that UT results have not identified any corrosion of the containment liner on the concrete side and operating experience has not identified significant signs of distress due to corrosion of embedded steel.

The staff reviewed the applicant's response and noted that it explained that the containment concrete met the guidance in ACI 201.2R in regards to a low permeability concrete and minimum chlorides. Permeability and chloride content are two of the primary factors regarding the ability of concrete to protect embedded steel. Concrete with low permeability and low chloride content provides maximum protection to embedded steel. Based on its review, the staff finds the applicant's response acceptable because it explains that Salem containment concrete meets the guidance in ACI 201.2R for low permeability concrete with low chlorides. The staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.2.1-01 is resolved.

During the staff's review of operating experience for the ASME Section XI, Subsection IWE and Structures Monitoring programs, it was noted that degradation has been identified on accessible portions of the containment liner near the moisture barrier. Indications of borated water contacting the liner have also been noted sporadically during past outages. To address this, the staff issued several RAIs requesting that the applicant explain how aging would be managed. The staff's review and resolution of these issues, including the RAIs, can be found in the ASME Section XI, Subsection IWE Program and Structures Monitoring Program evaluations documented in SER Sections 3.0.3.2.13 and 3.0.3.2.15, respectively.

On the basis of its review, the staff finds the applicant's evaluation of the AERM acceptable. The applicant has either demonstrated why corrosion is insignificant or committed to additional inspections for areas where corrosion may be significant (see SER Sections 3.0.3.2.13 and 3.0.3.2.15).

<u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. LRA Section 3.5.2.2.1.5 addresses loss of prestress due to relaxation, shrinkage, creep, and elevated temperature. In the LRA, the applicant stated that loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for the Salem containment structure is not applicable since the Salem containment structure does not use a prestressed concrete containment design.

The staff finds the applicant's evaluation acceptable that this aging effect is not applicable on the basis that the Salem containment is a reinforced concrete containment with no post-tensioned concrete.

<u>Cumulative Fatigue Damage</u>. LRA Section 3.5.2.2.1.6 addresses cumulative fatigue damage. In the LRA, the applicant stated that a TLAA evaluation for the transfer tube bellows was performed. The stainless steel transfer tube bellows are not part of the containment penetration bellows and are not part of the containment pressure boundary, but are a water-retaining boundary associated with the reactor cavity in the containment and the transfer pool in the fuel handling building. The applicant further stated that the TLAA evaluation shows that the projected number of cycles for 60 years is less than the design cycles. Thus, cracking of transfer tube bellows due to cyclic loading is not expected to occur through the period of extended operation. The applicant also stated that the TLAA is evaluated in accordance with 10 CFR 54.21(c) and evaluation of the TLAA is discussed in Section 4.5, "Fuel Transfer Tube Bellows Design Cycles." Cumulative fatigue damage and associated TLAA evaluations are only applicable to the stainless steel transfer tube bellows. The applicant explained that a fatigue analysis is not included in the CLB for containment penetrations (including penetration sleeves and dissimilar metal welds) and that cracking of the containment penetration bellows due to cyclic loading is not applicable because the containment penetration bellows located outside of the containment are not within the scope of license renewal and are not part of the containment leakage limiting boundary per UFSAR Section 3.8.1.6.8.10, "Piping Penetrations."

The staff reviewed LRA Section 3.5.2.2.1.6 against the criteria in SRP-LR Section 3.5.2.2.1.6, which state that fatigue analyses of penetrations are TLAAs as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed separately in SER Section 4.6.

The staff confirmed that there are no containment penetration bellows within the scope of license renewal at Salem. The staff's review of the applicant's evaluation of the remaining TLAAs can be found in SER Section 4.6.

Cracking Due to Stress-Corrosion Cracking. LRA Section 3.5.2.2.1.7 refers to Table 3.5.1, item 3.5.1-10 and addresses SCC of containment structures. The LRA states that item 3.5.1-11 is not applicable because it is only applicable to BWRs. The LRA, under item 3.5.1-10, indicates that SCC is not an applicable aging mechanism for the carbon steel penetration sleeves, stainless steel penetration bellows, and dissimilar metal welds. The LRA further indicates that the material of the containment liner and associated penetration sleeves is carbon steel and the high temperature piping systems penetrating the containment are generally made out of carbon steel. The LRA states that there are stainless steel and dissimilar metal welds associated with stainless steel piping welded to penetration sleeve cap plates.

The LRA states that SCC is only applicable to stainless steel under specific conditions, which include concentrations of chloride or sulfate contaminants, high stress, and temperatures greater than 60 °C (140 °F). The LRA also states that the containment pressure boundary welds between stainless steel piping and penetration sleeves, with normal operating temperatures above 60 °C (140 °F), are not highly stressed. LRA Section 3.5.2.2.1.7 further states that cracking of the containment stainless steel penetration bellows, due to SCC, is not applicable because the containment penetration bellows are not part of the containment leakage limiting boundary. LRA Section 3.5.2.2.1.6 also indicates that the containment penetration bellows located outside of the containment are not within the scope of license renewal.

The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7, which state that cracking due to SCC of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds could occur in all types of PWR and BWR containments. The SRP-LR further states that cracking due to SCC could also occur in stainless steel vent line bellows for BWR containments. The staff noted that the GALL Report, under item II.A3-2, indicates that this aging issue should be managed by the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program. Furthermore, the GALL Report indicates that transgranular SCC is a concern for dissimilar metal welds and that for the period of extended operation, Examination Categories E-B and E-F and additional appropriate examinations to detect SCC in bellows assemblies and dissimilar metal welds are warranted.

In its review, the staff noted that LRA Table 3.5.1, item 3.5.1-10 states that SCC will not occur at the penetration sleeves, penetration bellows, and associated welds within the scope of license renewal because the normal stress and environmental exposure conditions are not conducive to the development of SCC. However, LRA Table 3.5.2-3 (page 3.5-179) addresses loss of material due to pitting and crevice corrosion in the stainless steel penetration sleeves (cap plates) exposed to air with steam or water leakage. The applicant credited the 10 CFR Part 50, Appendix J Program and the ASME Section XI, Subsection IWE Program to manage loss of material for the components. LRA note 3 (page 3.5-187) also states that air with steam or water leakage environment is applicable to local areas inside the containment that are exposed to potential service water leakage or spray. In addition, LRA note 3 states that plant operating experience showed that metal components in this environment exhibit aging effects observed in an air-outdoor environment. Therefore, the staff noted that the AMR results of the applicant are in potential conflict with the applicant's claim that the normal environmental conditions are not conducive to the development of SCC.

LRA Section 3.5.2.2.1.7 further states that the containment pressure boundary welds between stainless steel piping and penetration sleeves, with normal operating temperatures above 60 °C (140 °F), are not highly stressed. However, the LRA does not provide a detailed technical basis for the applicant's claim that the penetration sleeves are not highly stressed so that the normal stress conditions are not conducive to the development of SCC.

By letter dated June 17, 2010, the staff issued RAI 3.5.2.2.1.7-01 requesting that applicant: (1) describe detailed operating experience in terms of the observation of pitting and crevice corrosion and SCC in the penetrations (penetration sleeves, bellows, and welds) and determine whether the operating experience supports the applicant's claim that the normal stress and environmental exposure conditions are not conducive to the development of SCC in these components, (2) clarify why the applicant claims that the environmental condition is not conducive to the development of SCC in the containment penetrations taking into account the "air with steam or water leakage" environment, (3) describe how the applicant determined that the welds between the stainless steel piping and penetration sleeves are not highly stressed and clarify whether the stress evaluation includes residual stresses and whether the condition including residual stresses is not conducive to the development of SCC in the containment penetrations, and (4) based on the information provided for the aforementioned requests, justify why SCC is not applicable to the stainless steel penetrations.

In its response dated July 15, 2010, the applicant stated that the hot pipe penetrations were installed with stainless steel expansion bellows on the outside of the containment and the bellows are not part of the pressure boundary. The applicant further indicated that the cold pipe penetrations have no expansion bellows. In addition, the applicant stated that in both cases, the containment pressure boundary is formed by the penetration sleeve, cap plates, piping, and the associated welds inside the containment. The applicant stated that the pipe penetration sleeves are constructed of carbon steel, while the cap plates are stainless steel or carbon steel. The applicant also stated that the containment penetration boundary welds of interest are the cap plate to penetration sleeve for those cap plates constructed of stainless steel (dissimilar metal welds) and the cap plate to penetrating pipe, for penetrating pipe constructed of stainless steel. In addition, the applicant stated that penetration sleeves and the cap plates inside the containment are exposed to a normal operating PWR containment atmosphere environment and that the "air with steam or water leakage" environment was conservatively assumed for penetration sleeves and cap plates where leakage has occurred from brackish water systems.

In its response dated July 15, 2010, which addresses the operating experience review, the applicant stated that a search of all available data in the corrective action database was performed for operating experience related to the penetration pressure boundary welds of interest and that there were no items associated with pitting, crevice corrosion, or SCC of the stainless steel containment penetration pressure boundary components or welds. The applicant also stated that this operating experience supports the position that normal stress and environmental exposure conditions are not conducive to the development of SCC.

In its response dated July 15, 2010, which addresses the evaluation of environmental conditions, the applicant stated that operating experience reviews revealed that both Salem Units 1 and 2 have previously experienced containment fan cooling Unit leaks in the containment. The applicant also stated that these previous event driven leaks have introduced a potential for the containment penetration pressure boundary stainless steel and dissimilar metal welds to be exposed to brackish water leakage. The applicant further stated that the elevations in the containment are separated for the most part by solid floors, but there are gaps between the floors and the containment wall that introduces a potential pathway to the containment penetrations located on the lower elevations. In addition, the applicant stated that corrective actions taken as a result of the past leaks included modifications which were implemented in 2008 at both units that substantially reduced the probability of water hammer events, which were the cause of the majority of the previous leaks.

The applicant also stated that as a result of the events and site sensitivity to the potential adverse effects of the service water leakage, a comprehensive event driven service water spill response procedure was developed to mitigate any possible similar events in the future. The applicant indicated that the applicant's procedure includes requirements for walkdowns, swipe sampling for chlorides, flushing, cleaning with demineralized water, and re-swiping to assure residual chloride levels are below an acceptable level. The applicant further stated that since there was a potential for an adverse environment at the penetrations in the past, it cannot be concluded that the environmental conditions conducive to the development of SCC were never present. Additionally, the applicant indicated that the operating experience reviews, liquid penetrant surface examinations, and the Appendix J Type "A" tests associated with the stainless steel and dissimilar metal containment penetration pressure boundary welds have not revealed any indications of SCC.

In its response dated July 15, 2010, which addresses the stress evaluation, the applicant indicated that it reviewed the calculations that verified the adequacy of the design for the piping penetrations. The applicant also indicated that in the calculations, the stresses on the penetrations and associated welds are low when compared to the allowable stresses. The applicant further indicated that residual weld stresses were not included in the evaluation that concluded the piping and penetration sleeves are not highly stressed. Additionally, the applicant indicated that since the threshold for the minimum level of tensile stress necessary for SCC to occur cannot be quantified and is also dependent on the relative severity of the corrosion-affecting parameters and other factors, it cannot be concluded with absolute certainty that the residual stresses present are not conducive to the development of SCC for the components.

In its response dated July 15, 2010, which addresses the applicability of SCC to the stainless steel containment penetrations and associated welds, the applicant indicated that operating experience reviews, including the results of the ASME Code Section XI, Subsection IWE inspections, liquid penetrant surface examinations, and Appendix J Type "A" tests, have not revealed any indications of SCC in the dissimilar metal welds associated with the cap plates. The applicant also stated, however, that based on the information provided above, it has been concluded there is a potential for SCC of the stainless steel and dissimilar metal welds associated with the containment penetration cap plate pressure boundary welds that are subject to normal operating temperatures greater than 60 °C (140 °F). The applicant further indicated that cracking due to SCC is considered potentially applicable for the penetration sleeve (cap plate) components that involve stainless steel material with normal operating temperatures greater than 60 °C (140 °F) exposed to an air with steam or water leakage environment in the containment structure.

In its response dated July 15, 2010, the applicant also revised LRA Sections 3.5.2.2.1.7, A.2.1.28, A.2.1.31, B.2.1.28, and B.2.1.31 and Tables 3.5.1 and 3.5.2-3 in order to include and manage cracking due to SCC for the stainless steel and dissimilar metal welds associated with the containment penetration pressure boundary with normal operating temperatures greater than 60 °C (140 °F). In its revision, the applicant also credited the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program to manage the aging effect. The applicant further indicated that the plant operating experience reviews, surface examinations, and the Appendix J tests have not revealed any indications of cracking or flaws, therefore, augmented or additional inspections are not warranted.

In its review, the staff finds the applicant's response acceptable because: (1) the applicant's operating experience review, including the results of surface examinations and the Appendix J tests, has not revealed any indication of pitting, crevice corrosion, or SCC associated with the stainless steel containment penetration pressure boundary welds, which supports the applicant's claim that the normal stress and environmental exposure conditions are not conducive to the occurrence of SCC in the components; (2) the applicant clarified that the "air with steam or water leakage" environment was conservatively assumed for the components where event driven leakage has occurred from brackish water systems; (3) the applicant's corrective actions and service water spill response procedure provide reasonable assurance that potential adverse effects of service water leakage can be prevented or mitigated adequately; (4) the applicant also clarified that residual weld stresses were not included in the applicant's stress analysis and it cannot be concluded with absolute certainty that the residual stresses present are not conducive to the occurrence of SCC; and (5) the applicant concluded, on the basis of the information and evaluation in response to the RAI, that there is a potential for SCC of the stainless steel and dissimilar metal welds subject to normal operating temperatures greater than 60 °C (140 °F) exposed to an air with steam or water leakage environment. On the basis of its review, the staff's concerns described in RAI 3.5.2.2.1.7-01 are resolved.

The staff also reviewed the applicant's ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.18, respectively. The staff finds that the credited programs are adequate to manage the aging effect because: (1) the applicant's use of the programs to manage the aging effect is consistent with the recommendation in the GALL Report and (2) the applicant's operating experience review results with the evaluation of the environmental conditions indicate no occurrence of SCC in the components and support the applicant's claim that no augmented or additional inspections are required to manage the aging effect for the components. On the basis of its review, the staff finds that the applicant's AMR results are consistent with GALL Report, Volume 2, item II.A3-2 and the applicant satisfied the acceptance criteria in SRP-LR Section 3.5.2.2.1.7.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1.7 criteria. For those items that apply to LRA Section 3.5.2.2.1.7, 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).

<u>Cracking Due to Cyclic Loading</u>. LRA Section 3.5.2.2.1.8 addresses cracking due to cyclic loading. In the LRA, the applicant stated that Salem is a PWR and that BWR components including suppression pool, BWR vent header, vent line bellows, and downcomers are not applicable. The applicant also stated that the containment penetration bellows are not within the scope of license renewal because they do not perform a containment structure pressure boundary or any other intended function. The containment penetration bellows located outside of the containment are not part of the containment leakage limiting boundary per UFSAR Section 3.8.1.6.8.10. The applicant further stated that the composite containment concrete shell and carbon steel liner and penetrations (including sleeves and dissimilar metal welds) are not subject to cyclic loading induced cracking, as analysis for the piping is bounding and enveloping for stresses in the penetrations (including sleeves and dissimilar welds). Cracking due to

fatigue loads is addressed, where applicable, as a TLAA for the associated piping in SER Section 4.3. Cracking is not predicted in the associated piping due to the low design loads and, therefore, is not expected in the containment liner and penetrations (including sleeves and dissimilar welds). The applicant stated that fine cracking of penetration sleeves, dissimilar welds, and the containment carbon steel liner are not expected at Salem and, therefore, the use of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs are adequate to manage the applicable aging effects of these components without supplemental inspection activities.

The staff reviewed LRA Section 3.5.2.2.1.8 against the criteria in SRP-LR Section 3.5.2.2.1.8, which state that cracking due to cyclic loading of the stainless steel shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) could occur in PWR containments. The existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J to manage this aging effect. However, VT-3 visual inspection may not detect fine cracks. The GALL Report recommends further evaluation for detection of this aging effect.

On the basis of its review, the staff finds the applicant's evaluation of the AERM acceptable. No in-scope stainless steel penetration sleeves, penetration bellows, or dissimilar metal welds are subject to cyclic loading induced cracking at Salem. Fatigue is addressed as a TLAA in SER Section 4.3. The staff's evaluations of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.18, respectively.

<u>Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw</u>. LRA Section 3.5.2.2.1.9 addresses loss of material (scaling, cracking, and spalling) due to freeze-thaw. In the LRA, the applicant stated that the ASME Section XI, Subsection IWL Program will be used to manage loss of material (scaling, cracking, and spalling) due to freeze-thaw of accessible containment structure concrete elements. The Salem containment structure is located in a region where weathering conditions are considered severe as shown in ASTM C 33-90, Figure 1. The applicant explained that the Salem containment structure is designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66. The applicant further explained that the type and size of aggregate, slump, cement, and additives have been established to produce durable concrete. Aggregates were tested in accordance with ASTM Specification C289-65 for potential reactivity, as well as in accordance with ASTM Specifications C29-60, C40-66, C127-59, C128-59, and C88-63. The coarse aggregate was a basic igneous rock consisting of diabase and basalt that was crushed and graded to meet the detail specifications. The applicant also stated that except for the service water intake structure, the Salem structures were designed to minimize exposure to moisture to reduce the potential for water absorption, minimizing the potential for damage from freeze-thaw conditions. The applicant further stated that an operating experience review has not identified significant loss of material (scaling, cracking, and spalling) of the accessible containment structure concrete. Inspections conducted in accordance with ASME Code Section XI, Subsection IWL identified isolated instances of minor local spalling and cracking of above-grade concrete and grout. Evaluation of spalling and cracking concluded that these aging effects have no significant impact on structural integrity of the containment structure. Therefore, the applicant stated that loss of material (scaling, cracking, and spalling) due to freeze-thaw of inaccessible concrete is insignificant and requires no aging management.

The staff reviewed LRA Section 3.5.2.2.1.9 against the criteria in SRP-LR Section 3.5.2.2.1.9, which notes that loss of material (scaling, cracking, and spalling) due to freeze-thaw could occur in PWR and BWR concrete containments. The existing program relies on ASME Code Section XI, Subsection IWL to manage this aging effect. The GALL Report recommends further evaluation of this aging for plants located in moderate to severe weathering conditions. GALL Report item II.A1-2 suggests that the existing concrete have an air content of 3 percent to 6 percent. Since the applicant stated that the weathering condition is severe and an air content was not specified in the LRA, it is unclear to the staff that guidance contained in GALL Report item II.A1-2 has been met. By letter dated June 7, 2010, the staff issued RAI 3.5.2.2.1-02 to address compliance of the Salem concrete to recommendations provided in GALL Report item II.A1-2.

In its response dated July 8, 2010, the applicant stated that the structural concrete mixes at Salem included fly ash and had a water-to-cement ratio between 0.46 and 0.56. The applicant also explained that air content was not a requirement in the Salem concrete specification; however, records indicated values from 1 percent to 5 percent. The applicant also explained that although this ratio is outside the GALL Report recommended range, concrete inspections during the plant's operating history have not revealed degradation attributed to freeze-thaw. The applicant further stated that freeze-thaw damage is greatly influenced by the degree of saturation of the concrete and the site is designed to maximize drainage and minimize concrete exposure to moisture. The applicant stated that freeze-thaw damage generally occurs slowly and in areas accessible for inspection, so any degradation that may occur in the future will be detected in a timely manner by the ASME Section XI, Subsection IWL and Structures Monitoring Program inspections, which occur on a 5-year frequency.

The staff reviewed the applicant's response and noted that the applicant has no site-specific operating experience with concrete freeze-thaw degradation. In addition, the credited ASME Section XI, Subsection IWL Program visual inspections provide assurance that any future degradation will be detected prior to a loss of intended function. Even though the water-to-cement ratio is outside the GALL Report suggested range, since the applicant does not have operating experience related to freeze-thaw degradation and has inspection programs in place, the staff finds that the applicant evaluated the AERM adequately and the staff's concern in RAI 3.5.2.2.1-02 is resolved.

<u>Cracking Due to Expansion and Reaction with Aggregates and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide</u>. LRA Section 3.5.2.2.1.10 addresses cracking due to expansion and reaction with aggregates and increase in porosity and permeability due to leaching of calcium hydroxide. In the LRA, the applicant stated that the Salem containment structure is designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66. The applicant also stated that aggregates were tested in accordance with ASTM Specification C289-65 for potential reactivity and Type II cement and fly ash were used in the concrete to provide increased resistance to leaching. The type and size of aggregate, slump, cement, and additives have been selected to produce durable concrete. Thus, the applicant stated that cracking due to expansion and reaction with aggregates is not applicable and requires no aging management. Increase in porosity and permeability due to leaching of calcium hydroxide is not significant and the Salem ASME Section XI, Subsection IWL Program is used as the AMP.

The staff reviewed LRA Section 3.5.2.2.1.10 against the criteria in SRP-LR Section 3.5.2.2.1.10, which state that cracking due to expansion and reaction with aggregates and increase in porosity and permeability due to leaching of calcium hydroxide could occur in concrete elements of concrete and steel containments. The GALL Report recommends further evaluation if the aggregate was not evaluated for potential expansion/reaction due to reactivity with the cementitious materials and suggests GALL AMP XI.S2, "ASME Section XI, Subsection IWL," as the AMP. GALL Report item II.A1-6 notes that an AMP for inaccessible concrete is not required if the concrete was constructed in accordance with the recommendations of ACI 201.2R-77.

The staff confirmed that the ASME Section XI, Subsection IWL Program is used at Salem to manage cracking, loss of material, and increase in porosity and permeability due to leaching of calcium hydroxide for the accessible portions of the concrete containment building. The staff's review of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.1.16. In its review, the staff noted that the LRA discussed ASTM C289-65; however, it made no mention of ASTM Specifications C227 or C295, which are discussed in the GALL Report as acceptable methods for identifying aggregates that do not react within concrete. In addition, the LRA did not clearly explain that the concrete was constructed in accordance with the recommendations of ACI 201.2R-77 to demonstrate that an AMP is not required for increase in porosity and permeability due to leaching of the concrete. To address these concerns, by letter dated June 7, 2010, the staff issued RAIs 3.5.2.2.1-03 and 3.5.2.2.1-04.

In its response dated July 8, 2010, the applicant stated that a review of Hope Creek and Salem records indicated that the same aggregate sources were used at both plants. The aggregates at Hope Creek were shown to be non-reactive in accordance with ASTM C295; therefore, the Salem aggregates can be considered non-reactive as well. The applicant further stated Type II Portland Cement was used, as recommended by ACI 201.2R, and fly ash was used to improve the concrete resistance to weak acids and sulfates and, therefore, to leaching of calcium hydroxide. In addition, the applicant stated that inspections of in-scope structures have not revealed degradation due to leaching of calcium hydroxide. Furthermore, the applicant stated that damage due to leaching would be most likely in areas exposed to flowing water, which are generally accessible and available for inspection. These areas, including the submerged components of the service water intake structure, will be used as a leading indicator for potential degradation of inaccessible areas, including inaccessible containment concrete.

The staff reviewed the applicant's responses and noted that the aggregate used in Salem concrete came from the same location as the Hope Creek aggregate, which was shown to be non-reactive using the ASTM C295 standard, as recommended in the GALL Report. The staff also noted that although the water-to-cement ratio and air content of the Salem concrete does not fall within the GALL Report recommended range, the site does not have experience with degradation due to leaching of calcium hydroxide. In addition, inspections of accessible concrete exposed to flowing water can be used as a "leading indicator" of degradation in inaccessible areas. Since the applicant has shown the Salem aggregates to be non-reactive, has explained how accessible concrete exposed to flowing water can be used to identify the possibility of leaching degradation in inaccessible concrete, and has programs to inspect for concrete degradation on an acceptable frequency, the staff finds that the applicant evaluated the AERM adequately and the staff's concerns in RAIs 3.5.2.2.1-03 and 3.5.2.2.1-04 are resolved.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1 criteria. For those line items that apply to LRA Section 3.5.2.2.1, 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).

3.5.2.2.2 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.

Aging of Structures Not Covered by the Structures Monitoring Program. LRA Section 3.5.2.2.2.1 addresses aging of structures not covered by the Structures Monitoring Program. In the LRA, the applicant stated that GALL Report structure Groups 2, 7, 8, and 9 do not exist; Groups 2 and 9 structures are BWR specific and thus not applicable; and there are no Group 7 concrete tanks. Concrete walls and structural steel with a missile barrier function are associated with some buildings and are addressed as an integral part of those parent structures. The applicant further stated that Salem has no separate Group 7 or 8 missile barrier structures. Steel tanks are addressed as a part of the mechanical systems and not as a Group 8 structure. Salem AMRs concluded that certain concrete aging effects or mechanisms identified in the GALL Report are not applicable to some of the Groups 1, 3, 4, and 5 structures as explained below and require no aging management. However, the applicant explained that Groups 1, 3, 4, and 5 accessible structures will be monitored for loss of material, cracking, increase in porosity and permeability, and loss of bond through the Structures Monitoring Program regardless of the causal mechanism.

The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.1, which state that the GALL Report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the structures monitoring program, including: (1) cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1–5, 7, and 9 structures; (2) increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1–5, 7, and 9 structures; (3) loss of material due to corrosion for Groups 1–5, 7, and 8 structures; (4) loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1–3, 5, 7–9 structures; (5) cracking due to expansion and reaction with aggregates for Groups 1–5 and 7–9 structures; (6) cracks and distortion due to increased stress levels from settlement for Groups 1–3 and 5–9 structures; and (7) reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1–3 and 5–9 structures. In addition, lockup due to wear may occur for Lubrite® radial beam seats in BWR drywells, RPV support shoes for PWRs with nozzle supports, SG supports, and other sliding support bearings and sliding support surfaces. The existing program relies on the structures monitoring program or ASME Code Section XI, Subsection IWF to manage this aging effect. The GALL Report recommends further evaluation only for structure-aging effect combinations not within the ISI (IWF) or structures monitoring programs.

(1) Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel for Groups 1–5, 7, and 9 Structures

In the LRA, the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1, 3, 4, and 5 structures are monitored by the Structures Monitoring Program and thus, further evaluation is not necessary.

The staff confirmed that Groups 1, 3, 4, and 5 structures subject to this AMR are in-scope of the applicant's Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(2) Increase in Porosity and Permeability, Cracking, and Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack for Groups 1–5, 7, and 9 Structures

In the LRA, the applicant stated that increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1, 3, 4, and 5 structures are monitored through the Structures Monitoring Program and thus, further evaluation is not necessary. The applicant also stated that leakage of treated borated water from the reactor cavity liners, while contained within the containment structures, has come into contact with the supporting concrete during refueling outages. In the LRA, the applicant further stated that the effects of borated water on the containment interior concrete were evaluated and found to be bounded by the effects due to similar leaks in the fuel handling building from the SFPs. The applicant stated that an analysis was conducted which shows that the effects of borated water on the reinforced concrete and structural margin is not significant and has no impact on structural integrity of the internal containment structures, the SFP, or the fuel handing building through the period of extended operation.

Since leakage of treated borated water from the reactor cavity liners, as well as the SFP liners, was noted to be occurring and has come into contact with the supporting concrete, it is unclear to the staff that leakage of the borated water has not resulted in degradation of either the concrete or embedded steel reinforcement that is inaccessible for inspection. Therefore, by letter dated April 15, 2010, the staff issued RAIs B.2.1.33-1 and B.2.1.33-2 requesting that the applicant provide more details on the SFP and the reactor cavity leakage and discuss how the integrity of inaccessible portions of the concrete and embedded steel reinforcement will be demonstrated during the period of extended operation.

The applicant responded by letter dated May 13, 2010. The staff's review of the responses and resolution of these issues can be found in the Structures Monitoring Program evaluation documented in SER Section 3.0.3.2.15. Further discussion of how the applicant addresses aging of inaccessible concrete can be found in SER Section 3.5.2.2.2, "Aging of Inaccessible Areas."

The staff confirmed that Groups 1, 3, 4, and 5 structures subject to this AMR are in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(3) Loss of Material Due to Corrosion for Groups 1–5, 7, and 8 Structures

In the LRA, the applicant stated that loss of material due to corrosion for Groups 1, 3, 4, and 5 structures and component supports is monitored through the Structures Monitoring Program and thus, a further evaluation is not necessary.

The staff confirmed that Groups 1, 3, 4, and 5 structures subject to this AMR are in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1–5 and 7–9 Structures

In the LRA, the applicant stated that loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1, 3, and 5 structures are monitored through the Structures Monitoring Program and thus, further evaluation is not necessary. The applicant further stated that Group 4 structures are inside the containment structure and protected from repeated freeze-thaw; thus not subject to loss of material and cracking due to freeze-thaw.

The staff confirmed that Groups 1, 3, 4, and 5 structures subject to this AMR are in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1–5 and 7–9 Structures

In the LRA, the applicant stated that cracking due to reaction with aggregates for Groups 1, 3, 4, and 5 structures is not applicable as concrete for Groups 1, 3, 4, and 5 structures was constructed in accordance with ACI 301-66 and aggregates were tested in accordance with ASTM Specification C289-65 for potential reactivity. The type and size of aggregate, slump, cement, and additives have been selected to produce durable concrete. Thus, the applicant stated that cracking due to expansion and reaction with aggregates is not applicable and requires no aging management. Nevertheless, concrete cracking due to any mechanism is monitored through the Structures Monitoring Program.

The staff confirmed that Groups 1, 3, 4, and 5 structures subject to this AMR are in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1–3 and 5–9 Structures

In the LRA, the applicant stated that Groups 1, 3, 4, and 5 structures are potentially subject to cracks and distortion due to increased stress levels from settlement. A dewatering system and porous concrete subfoundations are not used at Salem. The applicant further stated that structures whose foundations are founded on soil or the Vincentown Formation are potentially subject to cracks and distortion due to increased stress levels from settlement. Certain Group 3 structures are founded on concrete piles, which are encased in steel, and other Group 3 structures are founded on soil. For those structures founded on soil or the Vincentown Formation, cracks and distortion due to increased stress levels from settlement are applicable and will be monitored under the Structures Monitoring Program. For those Group 3 structures founded on concrete piles encased in steel, cracks and distortion due to increased stress levels from settlement is not applicable. Regardless, Groups 1, 3, 4, and 5 structures are monitored under the Structures Monitoring Program for cracks and distortion due to increased stress levels from settlement.

The staff confirmed that Groups 1, 3, 4, and 5 structures subject to this AMR are in-scope of the applicant's Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(7) Reduction in Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1–3 and 5–9 Structures

In the LRA, the applicant stated that Groups 1, 3, 4, and 5 structures are not subject to reduction in foundation strength, cracking, and differential settlement due to erosion of the porous concrete subfoundation because porous concrete subfoundations were not used at Salem.

Based on its review of documents supporting the LRA, the staff agrees this aging effect is not applicable because Salem has no porous concrete subfoundations.

(8) Lockup Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces

In the LRA, the applicant stated that the applicable material is Lubrite®. The SG supports include pinned steel connections and Lubrite® plates. Lockup due to wear in the indoor-air environment is managed using the ASME Section XI, Subsection IWF Program, therefore, no further evaluation is necessary. Sliding surfaces for other supports are pinned steel connections or carbon steel sliding surfaces for which Lubrite® is not used. The applicant stated that the RPV support shoes for the PWR nozzle supports, piping supports, RCP supports, and heat exchanger supports include sliding steel surfaces. Aging management of these surfaces is through the ASME Section XI, Subsection IWF Program.

The staff confirmed that sliding supports are within the scope of the ASME Section XI, Subsection IWF Program. SER Section 3.5.2.1.6 documents the staff's review for lockup due to wear for Lubrite® radial beam seats in BWR drywell and other sliding support surfaces. Since the sliding supports are within the scope of the ASME Section XI, Subsection IWF Program, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.1 criteria. For those line items that apply to LRA Section 3.5.2.2.2.1, the LRA is consistent with the GALL Report and 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).

Aging Management of Inaccessible Areas. LRA Section 3.5.2.2.2.2 addresses aging management of inaccessible areas (below-grade inaccessible concrete areas of Groups 1, 3, 5, and 7–9 structures).

The staff reviewed LRA Section 3.5.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2, which state that the GALL Report recommends further evaluation of certain structure/aging effect combinations, including: (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 for plants located in moderate to severe weathering conditions; (2) cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77; (3) cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures for plants whose structures are not included within the scope of the applicant's structures monitoring program; (4) increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel in below-grade inaccessible concrete areas of Groups 1, 3, 5, and 7–9 structures if the environment is aggressive; and (5) increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures if the concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures.

In the LRA, the applicant stated that Groups 1, 3, and 5 structures are located in a region where weathering conditions are considered severe as shown in ASTM C 33-90, Figure 1. GALL structure Groups 2, 7, 8, and 9 do not exist at Salem. Group 4 structures are containment internal structures and are not exposed to freeze-thaw conditions. The applicant further stated that concrete for Groups 1, 3, 4, and 5 structures is designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66, and testing of the concrete materials was in accordance with applicable ASTM standards as required by ACI. The Type II Portland cement conforms to ASTM C 150 and fly ash was used in the concrete mixtures. Concrete aggregates conform to the requirements of ASTM C 33-66. The type and size of aggregate, slump, cement, and additives have been established to produce durable concrete. Neither calcium chloride nor admixtures containing calcium chloride or other chlorides, sulfides, or nitrates were used in the concrete mixtures. The applicant also stated that structures were designed to minimize exposure to moisture to minimize water absorption, reducing the potential for damage from freeze-thaw conditions. The condition of concrete in the service water intake structure, as well as above-grade concrete of Groups 1, 3, and 5 structures is used as an indicator for inaccessible concrete and provides reasonable assurance that degradation of inaccessible structures will be detected before loss of an intended function. The LRA further states that a review of operating experience has not identified significant loss of material and cracking of the accessible Groups 1, 3, and 5 structures concrete. Therefore, the applicant stated that loss of material (spalling, scaling) and cracking due to freeze-thaw of inaccessible concrete are insignificant and require no aging management. However, inaccessible concrete will be inspected if excavated for any reason, as required by the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.2.1, which state that further evaluation is required for 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 for plants subjected to moderate to severe weathering conditions. The GALL Report suggests that the existing concrete have an air content of 3 percent to 6 percent. The air content recommended for concrete resistance to freezing and thawing by ACI 201.2R is 4.5 percent to 7.5 percent for severe exposure with a ±1.5 percent tolerance. The GALL Report also suggests a water-to-cement ratio between 0.35 and 0.45 for concrete exposed to potential freeze-thaw conditions. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff noted that in LRA Section 3.5.2.2.2.2.1, neither an air content nor a water-to-cement ratio was specified for the Salem concrete. To address this issue and compliance of the concrete to recommendations provided in ACI 201.2R, the staff issued RAI 3.5.2.2.1-02 by letter dated June 7, 2010. The applicant responded by letter dated July 8, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's approach to aging management of concrete degradation due to freeze-thaw, is included in SER Section 3.5.2.2.1, "Loss of Material Due to Freeze-Thaw."

Based on its review, the staff concludes that the applicant has adequately evaluated concrete degradation due to freeze-thaw and no additional plant-specific program is required for inaccessible areas.

(2) Cracking due to expansion and reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 1–5 and 7–9 structures.

In the LRA, the applicant stated that at Salem the concrete portions of Groups 1, 3, 4, and 5 structures are designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66 using the same concrete specification and standards as the containment structure. The applicant further stated that Groups 2, 7, 8, and 9 structures are not found at Salem. Aggregates were tested in accordance with ASTM Specification C289-65 for potential reactivity. The Type II Portland cement conforms to ASTM C 150 and fly ash was also used in the concrete mixtures. Thus, the applicant concluded that cracking due to expansion and reaction with aggregates is not significant and requires no aging management. However, the applicant further stated that inaccessible concrete for Groups 1, 3, and 5 structures will be inspected for cracking due to any mechanism if excavated for any reason, as required by the Structures Monitoring Program. Group 4 containment internal concrete structures are accessible and inspected by the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2.2, which state that the GALL Report recommends further evaluation of inaccessible areas of these groups of structures if the concrete was not constructed in accordance with the recommendations in ACI 201.2R-77. GALL Report item III.A1-2 states that investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54 or ASTM C227-50 can demonstrate that the aggregate is not reactive within the reinforced concrete. If either of these conditions is met, the GALL Report notes that aging management is not necessary.

In its review, the staff noted that the LRA discussed ASTM C289-65; however, it made no mention of ASTM C227 or C295 which are discussed in the GALL Report as acceptable methods for identifying aggregates that do not react within concrete. In addition, the LRA did not clearly explain that the concrete was constructed in accordance with the recommendations of ACI 201.2R-77 to demonstrate that an AMP is not required. By letter dated June 7, 2010, the staff issued RAI 3.5.2.2.1-03 to address these concerns. The applicant responded by letter dated July 8, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's evaluation of aging effects due to reactive aggregates, is included in SER Section 3.5.2.2.1, "Cracking Due to Expansion and Reaction with Aggregates."

On the basis of its review, the staff finds that the aggregates used at Salem are nonreactive. Therefore, cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas for Groups 1–5 and 7–9 structures are not aging effects for concrete elements and no additional plant-specific program is required.

(3) Cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures.

In the LRA, the applicant stated that Salem Groups 1, 3, 4, and 5 structures are potentially subject to cracks and distortion due to increased stress levels from settlement. However, the applicant stated that the aging effect/mechanism is not significant. The Salem design does not employ a dewatering system to control settlement and does not include porous concrete subfoundations. The applicant explained that measurements made throughout plant construction and during initial operation indicated a maximum settlement of approximately 12.7 millimeters (0.5 inch), which is not significant. The applicant further explained that the condition of the accessible and above-grade concrete is used as an indicator for the condition of the inaccessible and below-grade concrete and provides reasonable assurance that degradation of inaccessible structures will be detected before a loss of an intended function. In the unlikely event of cracks and distortion due to settlement occurring in below-grade or inaccessible concrete, the cracks and distortion would propagate into the above-grade or accessible concrete areas, and corrective actions will be initiated to evaluate the condition of inaccessible portions of the structures and determine if excavation of concrete for inspection is warranted. It is further stated in the LRA that Salem has not experienced cracks and distortion due to increased stress levels from settlement of structures. Inaccessible concrete for Groups 1, 3, and 5 structures will be inspected for cracking and distortion due to settlement if excavated for any reason, as required by the Structures Monitoring Program. Since the Groups 1, 3, 4, and 5 structures are monitored under the Structures Monitoring Program for cracks and distortion due to increased stress levels from settlement and a dewatering system is not used, further evaluation is not necessary.

The staff reviewed LRA Section 3.5.2.2.2.2.3 against the criteria in SRP-LR Section 3.5.2.2.2.2.3, which state that the GALL Report recommends verification of the continued functionality of the dewatering system during the period of extended operation if the plant’s CLB credits a dewatering system. The GALL Report recommends no further evaluation if this activity and these aging effects are included within the scope of the applicant’s Structures Monitoring Program.

On the basis of its review, the staff determined that cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures are not plausible aging effects due to the absence of these aging mechanisms. Salem does not use a dewatering system, and there are no porous subfoundations on the site. In addition, the applicant monitors the above-grade exposed concrete for the aging effect of cracking due to settlement under the Structures Monitoring Program. Therefore, no additional plant-specific program is required. The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

(4) Increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures.

In the LRA, the applicant stated that for Groups 1, 3, and 5 structures, the inaccessible below-grade reinforced concrete is subject to an aggressive environment due to elevated chloride levels. In the LRA, the applicant also stated that Groups 1, 3, and 5 structures are designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66. The Structures Monitoring Program includes inspection of concrete to detect indications of increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel. The applicant further stated that degradation of concrete due to cracking, loss of bond, and loss of material due to corrosion of embedded steel has not been experienced at Salem. Exposed portions of below-grade concrete will be examined by the Structures Monitoring Program when excavated for any reason, and groundwater chemistry will be monitored periodically in accordance with the enhanced Structures Monitoring Program. Also, the enhanced periodic inspections of the submerged portions of the intake structure will be used as indicators for the condition of below-grade structures. The applicant further stated that due to groundwater chemistry being bounded by river water chemistry, the use of submerged structures as a leading indicator for the potential degradation of below-grade structures provides reasonable assurance that degradation of inaccessible structures will be detected before a loss of an intended function. The applicant explained that if significant concrete degradation is identified at the service water intake structure, corrective actions will be initiated to evaluate the condition of inaccessible portions of the Groups 1, 3, and 5 structures. The applicant further stated that leakage of the SFPs in the fuel handling building has resulted in detectable levels of borated water in the seismic gap between the auxiliary building and the containment structure. Analyses indicate that the effects of borated water on the reinforced concrete and structural margin is not significant and has no impact on structural integrity of the SFP or the fuel handing building through the period of extended operation.

The staff reviewed LRA Section 3.5.2.2.2.2.4 against the criteria in SRP-LR Section 3.5.2.2.2.2.4, which state that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects and mechanisms in inaccessible areas of these groups of structures if the environment is aggressive. In the GALL Report, it is noted that for inaccessible areas of plants with non-aggressive groundwater/soil (i.e., pH greater than 5.5, chlorides less than 500 ppm, or sulfates less than 1,500 ppm), as a minimum the following should be considered: (a) examinations of the exposed portions of the below-grade concrete, when excavated for any reason and (b) periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations. Since the applicant does not have definite plans for inspections of inaccessible areas and the groundwater is aggressive, it is unclear to the staff that this is an adequate approach to managing aging of inaccessible concrete structures subjected to aggressive groundwater. By letter dated April 15, 2010, the staff issued RAI B.2.1.33-3 requesting that the applicant provide the locations and results of past groundwater sampling, as well as a basis to demonstrate the chloride levels in the groundwater were not causing degradation of the inaccessible concrete.

The applicant responded by letter dated May 13, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's evaluation of aging effects due to aggressive groundwater, is included in the staff's review of the Structures Monitoring Program documented in SER Section 3.0.3.2.15.

During its review, the staff also noted that borated water leakage from the SFP and refueling cavity liners may be causing degradation of the concrete or embedded steel reinforcement that is inaccessible for inspection. Therefore, by letter dated April 15, 2010, the staff issued RAIs B.2.1.33-1 and B.2.1.33-2 requesting that the applicant provide more details on the SFP and the reactor cavity leakage and discuss how the integrity of inaccessible portions of the concrete and embedded steel reinforcement will be demonstrated during the period of extended operation.

The applicant responded by letter dated May 13, 2010. In its response, the applicant explained that no degradation has been detected during past inspections and that a concrete core will be taken from the SFP at a known leakage location to verify no degradation has occurred. The staff found this approach acceptable. A more detailed discussion of the staff's review and resolution of this issue can be found in the Structures Monitoring Program evaluation documented in SER Section 3.0.3.2.15.

Based on its review, including RAIs B.2.1.33-1 and B.2.1.33-2, the staff concludes that the applicant has demonstrated that the aging effects due to aggressive chemical attack and corrosion of embedded steel will be adequately managed and no further evaluation is required.

(5) Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures

In the LRA, the applicant stated that leaching of calcium hydroxide is applicable for a flowing water environment that may occur to a limited extent in accessible or inaccessible portions of Groups 1, 3, 4, and 5 structures. The applicant stated that operating experience has found that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide is not significant and is adequately managed by the Structures Monitoring Program. In the LRA, the applicant further stated that inaccessible portions of the Group 5 structures may be subject to leaching of calcium hydroxide due to the known leakage of the borated water from the SFPs. In 2006, an inspection was conducted in accordance with ACI 349 to assess the structural condition of the SFP and the fuel handling building. The inspections identified no significant degradations or areas of structural distress. A similar inspection was conducted in 2009 to determine if any changes have occurred since the 2006 inspection with no significant changes noted. The applicant further stated that during the investigative phase of the SFP liner leakage, it was determined that leakage through small cracks in the stainless steel liner seam and plug welds did not drain properly because of clogged drains. As a result, water pressure behind the liner increased and forced borated water through small cracks in concrete and in the small gap between the liner and concrete. Maintenance activities were established to ensure the leak-chase system drains are cleared to allow drainage of the leakage. These activities will continue through the period of extended operation. The applicant explained that this reduces the amount of concrete exposed to borated water and ensures that the analysis performed to determine the impact of the borated water on the reinforced concrete remains bounding. The applicant further explained that the Structures Monitoring Program includes the reinforced concrete trench that collects the borated water drainage from the SFP telltale drains. Monitoring the reinforced concrete trench provides an indication of the actual concrete degradation in the Group 5 inaccessible areas and provides reasonable assurance that degradation of inaccessible structures will be detected before a loss of an intended function. The applicant explained that in the event inspection of the concrete trench identifies significant concrete degradation, corrective actions will be initiated to evaluate the condition of inaccessible portions of the Group 5 structures potentially exposed to borated water leakage.

The staff reviewed LRA Section 3.5.2.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.2.5, which state that the GALL Report recommends further evaluation of this aging effect for inaccessible areas of Groups 1–3, 5, and 7–9 structures if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

In its review, the staff noted that the LRA did not clearly explain that the concrete was constructed in accordance with the recommendations of ACI 201.2R-77 to demonstrate that further evaluation is not required for increase in porosity and permeability due to leaching of calcium hydroxide in inaccessible concrete. To address this concern, the staff issued RAI 3.5.2.2.1-04 by letter dated June 7, 2010. The applicant responded by letter dated July 8, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's evaluation of aging effects due to leaching of calcium hydroxide, is included in SER Section 3.5.2.2.1, "Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide."

During its review, the staff also noted that leakage of treated borated water from the reactor cavity liners, as well as the SFP liners, was noted to be occurring and has come into contact with the supporting concrete. It is unclear to the staff that leakage of the borated water has not resulted in degradation of either the concrete or embedded steel reinforcement that is inaccessible for inspection. Therefore, by letter dated April 15, 2010, the staff issued RAIs B.2.1.33-1 and B.2.1.33-2 requesting that the applicant provide more details on the SFP and the reactor cavity leakage and discuss how the integrity of inaccessible portions of the concrete and embedded steel reinforcement will be demonstrated during the period of extended operation.

In its response dated May 13, 2010, the applicant explained that no degradation has been detected during past inspections and that a concrete core will be taken from the SFP at a known leakage location to verify no degradation has occurred. The staff found this approach acceptable. A more detailed discussion of the staff's review and resolution of this issue can be found in the Structures Monitoring Program evaluation documented in SER Section 3.0.3.2.15.

Based on its review, including RAIs B.2.1.33-1 and B.2.1.33-2, the staff concludes that the applicant has demonstrated that the aging effects due to leaching of calcium hydroxide will be adequately managed and no further evaluation is required.

Based on the programs and evaluations identified, the staff concludes that the applicant's programs meet the criteria of SRP-LR Section 3.5.2.2.2.2. For those line items that apply to LRA Section 3.5.2.2.2.2, the LRA is consistent with the GALL Report and 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 of Concrete Structures Due to Elevated Temperature. LRA Section 3.5.2.2.2.3 addresses reduction of strength and modulus of concrete structures due to elevated temperature for Groups 1–5 structures. In the LRA, the applicant stated that Group 2 structures are BWR specific and Groups 1, 3, 4, and 5 concrete structures are not subject to general area temperatures greater than 65 °C (150 °F). Group 1 structures (control room area) and Group 3 structures, which include areas within the EQ program, are exposed to indoor conditioned air temperatures not greater than 49 °C (120 °F) during normal operation. Group 4 structures are exposed to air temperatures inside the containment structure. The applicant explained that the TSs and UFSAR limit the bulk air temperature inside the building during normal plant operation to 49 °C (120 °F). The bulk air temperature is maintained within the TS limits by recirculating air through cooling coils and by forced air through the reactor shield and reactor nozzle support areas. Group 3 structures, which include areas not within the EQ program, and Group 5 structures (fuel handling building) are structures with limited heat sources. Therefore, normal temperatures are less than 65 °C (150 °F). The applicant further explained that Groups 1, 3, 4, and 5 concrete structures are not subject to a local temperature greater 93 °C (200 °F). Penetration seal technology is designed to prevent surrounding concrete from exceeding 93 °C (200 °F) (penetration seal specification). Plant operating experience has not identified elevated local temperature as a concern for the Groups 1, 3, 4, and 5 concrete structures.

The staff reviewed LRA Section 3.5.2.2.2.3 against the criteria in SRP-LR Section 3.5.2.2.2.3, which state that reduction of strength and modulus of concrete due to elevated temperatures may occur in PWR and BWR Groups 1–5 concrete structures. ACI 349-85 specifies the concrete temperature limits for normal operation or any other long-term period and states that general area temperatures shall not exceed 65 °C (150 °F) except for local areas that are permitted to have temperatures not to exceed 93 °C (200 °F). The GALL Report recommends further evaluation of a plant-specific program if any portion of in-scope concrete structures exceeds these limits.

The staff noted that Groups 1–5 concrete elements do not exceed temperature limits associated with aging degradation due to elevated temperature. On the basis of its review, the staff finds that reduction in strength and modulus of elasticity due to elevated temperatures in concrete areas of Groups 1–5 structures is not a plausible AERM because concrete temperatures are below limits specified in ACI 349-85. Therefore, the staff finds that this is not an AERM for these components because the necessary condition does not exist.

<u>Aging Management of Inaccessible Areas for Group 6 Structures</u>. LRA Section 3.5.2.2.2.4 addresses aging management of inaccessible areas for Group 6 structures.

The staff reviewed LRA Section 3.5.2.2.2.4 against the criteria in SRP-LR Section 3.5.2.2.2.4.

(1) Increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Group 6 structures.

In the LRA, the applicant stated that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as implemented through the Structures Monitoring Program, will be used to manage cracking, loss of bond, and loss of material due to corrosion of embedded steel in accessible above-grade and submerged areas of water-control structures (Group 6 structures). The applicant also stated that river water chloride content is variable and ranges from 5,500 to 8,300 ppm. The groundwater and river water are, therefore, considered aggressive environments due to chloride levels. The reinforced concrete for Group 6 structures is designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66. Exposed portions of below-grade concrete will be examined by the Structures Monitoring Program when excavated for any reason and groundwater chemistry will be monitored periodically in accordance with the Structures Monitoring Program. The applicant also stated that the enhanced 5-year periodic inspections of the submerged portions of the intake structure will be used as indicators for the condition of below-grade portions of the structures. In the event inspection of submerged structures identifies significant concrete degradation at the service water intake structure, corrective actions will be initiated to evaluate the condition of inaccessible below-grade portions of the Group 6 structures.

The staff reviewed LRA Section 3.5.2.2.2.4.1 against the criteria in SRP-LR Section 3.5.2.2.2.4.1, which state that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects in inaccessible areas if the environment is aggressive. The staff's review for these aging effects for inaccessible concrete elements of Groups 1–3, 5, and 7–9 structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas." The staff noted that inspections of Group 6 structures are performed under the Structures Monitoring Program, which is consistent with and integrates the elements of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

Since the applicant does not have definite plans for inspections of inaccessible areas and the groundwater is aggressive, it is unclear to the staff that this is an adequate approach to managing aging of inaccessible concrete structures subjected to aggressive environments. Therefore, by letter dated April 15, 2010, the staff issued RAI B.2.1.33-3 requesting that the applicant provide the locations and results of past groundwater sampling, as well as a basis to demonstrate that the chloride levels in the groundwater were not causing degradation of the inaccessible concrete.

The applicant responded by letter dated May 13, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's evaluation of aging effects due to aggressive groundwater, is included in the staff's review of the Structures Monitoring Program documented in SER Section 3.0.3.2.15.

Based on its review, the staff concludes that the applicant has demonstrated that the aging effects due to aggressive chemical attack and corrosion of embedded steel will be adequately managed and no further evaluation is required for inaccessible areas of Group 6 structures.

(2) Loss of material (spalling, scaling) and cracking due to freeze-thaw that could occur in below-grade inaccessible concrete areas of Group 6 structures.

In the LRA, the applicant stated that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, as implemented by the Structures Monitoring Program, will be used to manage loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of water-control structures (Group 6 structures). Group 6 structures are located in a region where weathering conditions are considered severe as shown in ASTM C33-90, Figure 1. The applicant further stated that structures are designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66 that precludes significant loss of material (spalling, scaling) and cracking due to freeze-thaw. The applicant also stated that the condition of exposed above-grade and submerged concrete of Group 6 structures is used as an indicator for inaccessible concrete and provides reasonable assurance that degradation of inaccessible structures will be detected before a loss of an intended function. In the event inspection of above-grade concrete structures or submerged structures identifies significant concrete degradation due to freeze-thaw, corrective actions will be initiated to evaluate the condition of inaccessible below-grade portions of Group 6 structures. The applicant stated that review of operating experience has not identified significant signs of distress due to freeze-thaw of concrete components of Group 6 structures; therefore, loss of material (spalling, scaling) and cracking due to freeze-thaw of inaccessible concrete are insignificant and require no aging management.

The staff reviewed LRA Section 3.5.2.2.2.4.2 against the criteria in SRP-LR Section 3.5.2.2.2.4.2, which state that the GALL Report recommends further evaluation of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions. The staff's review for these aging effects for inaccessible concrete elements of Groups 1–3, 5, and 7–9 structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas." The staff noted that inspections of accessible Group 6 structures are performed under the Structures Monitoring Program, which is consistent with and integrates the elements of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. GALL Report item III.A6-5 suggests that aging management is not necessary if the existing concrete has an air content of 3 percent to 6 percent and a water-to-cement ratio between 0.35 and 0.45 for concrete exposed to potential freeze-thaw conditions. The staff noted that in LRA Section 3.5.2.2.2.4.2, neither an air content nor a water-to-cement ratio is specified for the Salem concrete.

To address this issue and compliance of the concrete to recommendations provided in ACI 201.2R, the staff issued RAI 3.5.2.2.1-02 by letter dated June 7, 2010. The applicant responded by letter dated July 8, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's approach to aging management of concrete degradation due to freeze-thaw, is included in SER Section 3.5.2.2.1, "Loss of Material Due to Freeze-Thaw."

Based on its review, the staff concludes that the applicant has adequately evaluated concrete degradation due to freeze-thaw and no additional plant-specific program is required for inaccessible areas of Group 6 structures.

(3) Cracking due to expansion and reaction with aggregates, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide could occur in below-grade inaccessible reinforced concrete areas of Group 6 structures.

In the LRA, the applicant stated that cracking due to expansion and reaction with aggregates is not applicable for both accessible and inaccessible areas of reinforced concrete of Group 6 structures. Aggregate materials were tested in accordance with ASTM C289-65 for potential reactivity. The reinforced concrete for Group 6 structures is designed in accordance with ACI 318-63 and constructed in accordance with ACI 301-66. Cracking due to expansion and reaction with aggregates has not been experienced at Salem.

The staff reviewed LRA Section 3.5.2.2.2.4.3 against the criteria in GALL Report item III.A6-2, which notes that, according to NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54 can demonstrate that these aggregates do not react within reinforced concrete. The staff's review for cracking due to expansion and reaction with aggregates for inaccessible concrete elements of Groups 1–5 and 7–9 structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas."

In its review, the staff noted that the LRA discussed ASTM C289-65; however, it made no mention of ASTM C227 or C295 which are discussed in the GALL Report as acceptable methods for identifying aggregates that do not react within concrete. In addition, the LRA did not clearly explain that the concrete was constructed in accordance with the recommendations of ACI 201.2R-77 to demonstrate that an AMP is not required. To address these concerns, by letter dated June 7, 2010, the staff issued RAI 3.5.2.2.1-03. The applicant responded by letter dated July 8, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's evaluation of aging effects due to reactive aggregates, is included in SER Section 3.5.2.2.1, "Cracking Due to Expansion and Reaction with Aggregates."

Based on its review, the staff concludes that the aggregates used at Salem are nonreactive. Therefore, cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas for Group 6 structures are not aging effects for concrete elements and no additional plant-specific program is required.

In the LRA, the applicant further stated that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide of reinforced concrete in accessible and inaccessible areas of water-control structures (Group 6 structures) subject to a flowing water environment will be managed by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as implemented by the applicant's Structures Monitoring Program.

Leaching is a potential aging mechanism applicable to submerged portions of Group 6 structures exposed to flowing water. However, these areas are accessible for underwater inspection and for inspections when dewatered. The enhanced periodic inspections of the submerged portions of the intake structure of the Structures Monitoring Program will be used to manage this aging effect and mechanism. Leaching is applicable to inaccessible concrete that is buried as it may be subject to a flowing water environment through cracks. Operating experience at Salem has not identified increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide for inaccessible below-grade portions of Group 6 structures as significant. Inaccessible concrete will be inspected if excavated for any reason, as required by the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.4.3 against the criteria in SRP-LR Section 3.5.2.2.2.4.3, which state that the GALL Report recommends further evaluation of inaccessible areas if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77. The staff's review for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide for inaccessible concrete elements of Groups 1–3, 5, and 7–9 structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas."

The staff noted that inspections of Group 6 structures are performed under the Structures Monitoring Program, which is consistent with and integrates the elements of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff noted, however, that the LRA did not state that the concrete was constructed in accordance with the recommendations of ACI 201.2R-77 as specified in GALL Report item III.A6-6. To address this concern, the staff issued RAI 3.5.2.2.1-04, by letter dated June 7, 2010. The applicant responded by letter dated July 8, 2010. A discussion of the staff's review of the response, as well as the staff's acceptance of the applicant's evaluation of aging effects due to leaching of calcium hydroxide, is included in SER Section 3.5.2.2.1, "Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide."

Based on its review, the staff concludes that the applicant has demonstrated that the aging effects due to leaching of calcium hydroxide will be adequately managed and no further evaluation is required.

Based on the programs and evaluations identified, the staff concludes that the applicant's programs meet the criteria of SRP-LR Section 3.5.2.2.2.4. For those line items that apply to LRA Section 3.5.2.2.2.4, the LRA is consistent with the GALL Report and 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 Stress-Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion. LRA Section 3.5.2.2.2.5 addresses cracking due to SCC and loss of material due to pitting and crevice corrosion for Groups 7 and 8 stainless steel tank liners.

In the LRA, the applicant stated that Salem does not have Groups 7 and 8 stainless steel tank liners and further evaluation for the effects of cracking due to SCC and loss of material due to pitting and crevice corrosion is not applicable.

The staff reviewed LRA Section 3.5.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.5, which state that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur for Groups 7 and 8 stainless steel tank liners exposed to standing water. The GALL Report recommends further evaluation of plant-specific programs to manage these aging effects.

The staff verified that Salem does not have any Group 7 concrete tanks within the scope of license renewal and that steel tanks, including liners, are addressed as part of the mechanical systems. Since there are no components within scope, the staff agrees that this aging effect does not apply.

Aging of Supports Not Covered by the Structures Monitoring Program. LRA Section 3.5.2.2.2.6 addresses aging of supports not covered by the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6 against the criteria in SRP-LR Section 3.5.2.2.2.6.

(1) Loss of Material Due to General and Pitting Corrosion for Groups B2–B5 Supports

In the LRA, the applicant stated that loss of material due to general and pitting corrosion for Groups B2–B5 supports is covered under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6.1 against the criteria in SRP-LR Section 3.5.2.2.2.6, which state that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

The staff confirmed that the component support/aging effect combination of loss of material due to general and pitting corrosion for Groups B2–B5 supports is managed by the Structures Monitoring Program; therefore, further evaluation is not necessary. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

(2) Reduction in Concrete Anchor Capacity Due to Degradation of the Surrounding Concrete for Groups B1–B5 Supports

In the LRA, the applicant stated that reduction in anchor capacity due to degradation of the surrounding concrete for Groups 1–5 supports is covered under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6.2 against the criteria in SRP-LR Section 3.5.2.2.2.6.2, which state that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

The staff confirmed that the component support/aging effect combination of reduction in anchor capacity due to degradation of surrounding concrete for Groups 1–5 supports is managed by the Structures Monitoring Program; therefore, further evaluation is not necessary. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

(3) Reduction/Loss of Isolation Function Due to Degradation of Vibration Isolation Elements for Group B4 Supports

In the LRA, the applicant stated that reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports is covered under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6.3 against the criteria in SRP-LR Section 3.5.2.2.2.6.3, which state that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

The staff confirmed that the reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports is managed by the Structures Monitoring Program; therefore, further evaluation is not necessary. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

Based on the programs and evaluations identified, the staff concludes that the applicant's programs meet the criteria of SRP-LR Section 3.5.2.2.2.6. For those line items that apply to LRA Section 3.5.2.2.2.6, the LRA is consistent with the GALL Report and 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>Cumulative Fatigue Damage Due to Cyclic Loading</u>. In the LRA, the applicant stated that the CLB contains no fatigue analysis for component support members, anchor bolts, and welds of Groups B1.1, B1.2, and B1.3 component supports. Therefore, a TLAA is not evaluated in accordance with 10 CFR 54.21(c) for these components.

The staff reviewed LRA Section 3.5.2.2.2.7 against the criteria in SRP-LR Section 3.5.2.2.2.7, which state that fatigue of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports is a TLAA as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c).

The staff verified that at Salem, the CLB contains no fatigue analysis for component support members, anchor bolts, and welds of Groups B1.1, B1.2, and B1.3 component supports.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2 criteria. For those line items that apply to LRA Section 3.5.2.2.2, the staff determines that the LRA is consistent with the GALL Report and 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).

3.5.2.2.3 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 That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-17, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.5.2-1 through 3.5.2-17, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line 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 line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line 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 line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-4, 3.5.2-7, 3.5.2-8, 3.5.2-10, 3.5.2-13, 3.5.2-15, and 3.5.2-16 were revised as a result of the response to RAI B.2.1.9-01, dated July 8, 2010. The revision added AMR items in these tables to reference the applicant's Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff notes that the Bolting Integrity Program is supplemented by other AMPs including but not limited to the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection programs. These other AMPs supplement the Bolting Integrity Program by implementing the requirements of the Bolting Integrity Program for pressure-retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action accurately adds the related line items to reference the Bolting Integrity Program; however, the technical evaluations documented in the SER do not change since the management of the aging effect will still be implemented by the AMP identified in conjunction with the Bolting Integrity Program.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.5.2.3.1 Containments, Structures, and Component Supports – Auxiliary Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, which summarizes the results of AMR evaluations for the auxiliary building component groups.

In LRA Table 3.5.2-1, the applicant stated that aluminum structural bolting exposed to indoor or outdoor air, carbon and low-alloy or galvanized steel structural bolting exposed to outdoor air, and stainless steel structural bolting exposed to indoor or outdoor air are being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line item cites generic note H indicating that for the line items, the aging effect is not in the GALL Report for this component, material, and environment combination. The AMR line item also cites a plant-specific note stating that based on industry standards and operating experience, age-related loss of preload due to self-loosening of structural bolting could be caused by vibration, flexing of the joint, or cyclic shear loads that could occur in any environment. The plant-specific note also states that these causes are considered in the design of structural connections and eliminated by initial preload bolt torquing and that loss of preload due to self-loosening of structural bolting is not significant and will not impact structural intended functions. The plant-specific note further states that loss of preload due to self-loosening of structural bolts will be managed through the Structures Monitoring Program.

The staff reviewed all AMR result line items in the GALL Report where the component and material is aluminum structural bolting exposed to indoor or outdoor air, carbon and low-alloy or galvanized steel structural bolting exposed to outdoor air, and stainless steel structural bolting exposed to indoor or outdoor air and confirmed that there are no aging effect entries in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff notes that the Structures Monitoring Program includes visual inspections that are capable of identifying loss of preload in bolted connections by identifying loosening of components which would indicate a loss of preload. The staff also notes that the loss of preload in bolted connections is dependent on such mechanisms as vibration or flexing and is not dependent on the specific air environment to which the bolt is exposed. The staff further notes that the Bolting Integrity Program provides plant instructions for installation and torquing of bolted connections that are based on recommendations in EPRI guidance documents recommended in GALL AMP XI.M18, "Bolting Integrity." The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program includes visual inspections which can detect loss of preload and has incorporated industry guidance to prevent loss of preload into its plant instructions that manage loss of preload for all bolting within its scope.

For component type "hatches/plugs," the applicant stated that reinforced concrete encased in steel has no AERMs and does not require an AMP. This item references generic note G and plant-specific note 3 which states, "Concrete encased in steel is protected from environments that promote age related degradations." The applicant stated that these components have the intended function of missile barrier, shelter/protection, or structural support. The staff reviewed the GALL Report and verified that it includes no AMR item for this component, material, and environment combination. The staff finds that since the reinforced concrete is encased in steel and thus protected from the environment, it is not subject to any AERMs. On the basis of its review, the staff concludes that the reinforced concrete encased in steel in the auxiliary building is not subject to any AERMs and that the applicant need not credit any AMP to manage the hatches/plugs.

For component type “penetration seals,” the applicant proposed to assign grout to the Structures Monitoring Program to manage the aging effect of cracking/shrinkage in an indoor, outdoor air, or groundwater/soil environment. This item references note F and plant-specific note 5 which states, “Based on industry standards and guidelines, grout is susceptible to cracking due to shrinkage in this environment. However, shrinkage cracking occurs early in plant life and is not expected to be significant for the extended period of operation. Nevertheless, the aging effect will be monitored through the Structures Monitoring Program.” The applicant stated that these components have the intended functions of either shielding, flood barrier, high-energy line break (HELB)/moderate-energy line break (MELB) shielding, or shelter/protection and are examined using the Structures Monitoring Program as the primary AMP. The staff’s review of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.15. Since the Structures Monitoring Program has been enhanced to inspect penetration seals for indications of deterioration or distress including evidence of leaching, loss of material, cracking, and loss of bond as defined in ACI 201.1R at a frequency of 5 years, the staff finds that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

For one component type “penetration seals,” the applicant proposed to assign grout to the Structures Monitoring Program to manage the aging effect of loss of material (spalling, scaling), cracking/freeze-thaw, increase in porosity and permeability, and aggressive chemical attack in an air-outdoor or groundwater/soil environment. This item references note F and plant-specific note 6 which states, “The aging effects and aging management program identified for this material/environments combination are consistent with industry guidance.” The applicant stated that these components have the intended functions of flood barrier or shelter/protection and are examined using the Structures Monitoring Program as the primary AMP. The staff’s review of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.15. Since the Structures Monitoring Program has been enhanced to inspect penetration seals for indications of deterioration or distress including evidence of leaching, loss of material, cracking, and loss of bond as defined in ACI 201.1R at a frequency of 5 years, the staff finds that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

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 Containments, Structures, and Component Supports – Component Supports Commodity Group – Summary of Aging Management Evaluation – LRA Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the component supports commodity group component groups.

In LRA Table 3.5.2-2, the applicant stated that stainless steel bolting and supports for ASME Class 1, 2, and 3 piping and components exposed to air with steam or water leakage are being managed for loss of material by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note G. The AMR line items also cite plant-specific note 3, indicating that the air with steam or water leakage environment is applicable to local areas within containment that are exposed to potential service water leakage or spray and that plant operating experience has shown that components in this environment exhibit aging similar to those that would be experienced in an outdoor air environment.

The staff reviewed the applicant’s ASME Section XI, Subsection IWF Program and its evaluation is documented in SER Section 3.0.3.1.17. The staff finds the applicant’s program acceptable to manage aging for these components because it includes periodic visual inspections of ASME Class 1, 2, and 3 bolting and supports to detect loss of material and has incorporated the guidance in EPRI TR-104213 regarding proper selection, lubrication, and installation of bolting.

In LRA Table 3.5.2-2, the applicant stated that stainless steel bolting and supports for cable trays, conduits, HVAC ducting, tube track, instrument tubing, and non-ASME piping and components exposed to air with steam or water leakage are being managed for loss of material by the Structures Monitoring Program. The AMR line items cite generic note G. AMR line items also cite plant-specific note 3, indicating that the air with steam or water leakage environment is applicable to local areas within containment that are exposed to potential service water leakage or spray and that plant operating experience has shown that components in this environment exhibit aging similar to that experienced in an outdoor air environment.

The staff reviewed the applicant’s Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff finds the applicant’s program acceptable to manage aging for these components because it includes periodic visual inspections of bolting and supports to detect loss of material and has incorporated the guidance in EPRI TR-104213 regarding proper selection, lubrication, and installation of bolting.

In LRA Table 3.5.2-2, the applicant stated that stainless steel bolting and supports for ASME Class 1 piping and components exposed to indoor air are being managed for loss of preload due to self-loosening by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note H.

The staff reviewed the applicant’s ASME Section XI, Subsection IWF Program and its evaluation is documented in SER Section 3.0.3.1.17. The staff finds the applicant’s program acceptable to manage aging for these components because it includes periodic visual inspections of ASME Class 1, 2, and 3 bolting and supports to detect loss of preload and has incorporated the guidance in EPRI TR-104213 regarding proper selection, lubrication, and installation of bolting to prevent loss of preload.

In LRA Table 3.5.2-2, the applicant stated that stainless steel bolting and supports for cable trays, conduits, HVAC ducting, tube track, instrument tubing, and non-ASME piping and components exposed to indoor air are being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H.

The staff reviewed the applicant’s Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff finds the applicant’s program acceptable to manage aging for these components because it includes periodic visual inspections of bolting and supports to detect loss of preload and has incorporated the guidance in EPRI TR-104213 regarding proper selection, lubrication, and installation of bolting to prevent loss of preload.

In LRA Table 3.5.2-2, the applicant stated that carbon or low-alloy steel supports for ASME Class 1, 2, and 3 piping and components exposed to air with steam or water leakage are being managed for loss of material due to general, pitting, and crevice corrosion by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note G. The applicant also stated that carbon and low-alloy steel supports for ASME Class 2 and 3 piping and components exposed to outdoor air are being managed for loss of preload due to self-loosening by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note H.

The staff reviewed the applicant's ASME Section XI, Subsection IWF Program and its evaluation is documented in SER Section 3.0.3.1.17. The staff noted that the ASME Section XI, Subsection IWF Program manages loss of material and loss of preload by conducting visual inspections to detect degradation before loss of intended functions. The staff finds the applicant's management of carbon or low-alloy steel supports for ASME Class 1, 2, and 3 piping and components for loss of material and loss of preload acceptable because: (1) the ASME Section XI, Subsection IWF Program performs visual inspections of supports for loss of preload and loss of material; and (2) the program has incorporated industry guidance on proper selection of bolting materials, lubricants, and installation torque, which is consistent with the recommendations in the GALL Report for managing these components for loss of material and loss of preload.

In LRA Table 3.5.2-2, the applicant stated that galvanized, carbon, or low-alloy steel bolting or supports for cable trays, conduits, HVAC ducts, tube tracks, instrument tubing, non-ASME piping and components, EDG, HVAC system components, miscellaneous mechanical equipment, platforms, pipe whip restraints, jet impingement shields, masonry walls, other miscellaneous structures, racks, panels, cabinets, and enclosures for electrical equipment or instrumentation exposed to air with steam or water leakage are being managed for loss of material due to general, pitting, and crevice corrosion and exposed to outdoor air are being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items that refer to exposure to air with steam or water leakage cite generic note G. The AMR line items that refer to exposure to outdoor air cite generic note H.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff noted that the Structures Monitoring Program manages loss of preload and loss of material for bolting by conducting visual inspections of exposed bolting surfaces for loss of material, loose nuts, missing bolts, or other indications. The staff finds the applicant's Structures Monitoring Program acceptable to manage galvanized, carbon, or low-alloy steel bolting or supports exposed to air with steam or water leakage or outdoor air because: (1) it includes visual inspections targeted at identifying loss of material and loss of preload and (2) has incorporated industry guidance regarding proper selection of bolting materials, lubricants, and installation torque to prevent and mitigate loss of preload and loss of material, which is consistent with the GALL Report recommendations for managing these aging effects.

For one component type "supports for ASME Class 1 piping and components (high strength steel bolting for NSSS component supports)," the applicant stated that high-strength stainless steel bolting with yield strength greater than 150 ksi has no AERMs and does not require an AMP. This item references generic note G and plant-specific notes 6 and 7. Plant-specific note 6 states, "Loss of preload/self loosening is not applicable because the bolts are not required to be preloaded by design. Also, the bolt nuts are either tack welded or lock wired to prevent undesirable self-loosening." Note 7 states:

> Supports for Unit 2 SGs have high-strength stainless steel bolts (Carpenter Custom alloy 445 H900), with actual yield strength greater than 150 ksi. The bolts are not preloaded (not torqued) and are not subjected to tensile stress or a corrosive environment. Therefore, cracking due to stress corrosion cracking is not an aging effect requiring management. Also, loss of material due to corrosion is not an aging effect requiring aging management for the bolt material (stainless steel) consistent with NUREG-1801, Volume 2 Item No. III.B1.1-9.

Since the bolting has an intended function associated with structural support for the Unit 2 SGs, it is unclear to the staff why the stainless steel bolting will not be examined during the period of extended operation under an AMP such as the ASME Section XI, Subsection IWF Program for loss of intended function. By letter dated June 7, 2010, the staff issued RAI 3.5.2.3-01 to address this issue.

In its response dated July 8, 2010, the applicant stated that the possible AERMs for high-strength bolting exposed to an air environment are loss of material, loss of preload, and SCC. The applicant further explained that according to GALL Report item III.B1.1-9, stainless steel support members in an indoor uncontrolled air environment are not susceptible to loss of material. The applicant also explained that the bolts are not susceptible to loss of preload because the bolts are not preloaded. Finally, the applicant explained that the bolts are not susceptible to SCC because they are not subject to an environment containing contaminants nor are they subjected to sustained tensile stresses. Therefore, the applicant did not identify any AERMs for the identified bolting. Nevertheless, the ASME Section XI, Subsection IWF Program requires inspection of the SG component support bolting.

The staff reviewed the applicant's response and found it acceptable because it explained why there are no expected AERMs associated with the Unit 2 SG high-strength stainless steel bolts. In addition, the response explained that the bolts are within the scope of the ASME Section XI, Subsection IWF Program and will be inspected for missing or detached bolts and nuts. Therefore, the staff finds that the applicant has adequately addressed aging of these components and the staff's concern in RAI 3.5.2.3-01 is resolved.

For component types "supports for ASME Class 1 piping" and "components and supports for ASME Class 2 and 3 piping and components (support members; welds; bolted connections; support anchorage to building structure)," the applicant stated that stainless steel or carbon and low-alloy steel bolting in an air-indoor or air-outdoor environment is managed for loss of preload/self-loosening by the ASME Section XI, Subsection IWF Program. These items reference note H and plant-specific notes 1 and 2. Plant-specific note 1 states, "ASME Section XI, Subsection IWF is the applicable aging management program for this component." Plant-specific note 2 states:

> Based on industry standards and operating experience[,] age related loss of preload/self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload/self-loosening of structural bolting is not significant and will not impact

structural intended functions. Nevertheless, loss of preload/self-loosening will be monitored through the applicable aging management program.

The staff's review of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.17. Since the ASME Section XI, Subsection IWF Program requires periodic visual inspections of ASME Class 1, 2, and 3 piping and component support members for loss of material and loss of mechanical function, including inspection of bolting for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts and nuts, and relies on design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque, the staff finds that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

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 Containments, Structures, and Component Supports – Containment Structure – Summary of Aging Management Evaluation – LRA Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the containment structure component groups.

In LRA Table 3.5.2-3, the applicant stated that stainless steel insulation jacketing, miscellaneous steel, penetration sleeves, steel components, steel elements, and tube track components exposed to air with steam or water leakage are being managed for loss of material due to pitting and crevice corrosion by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs; Structures Monitoring Program; or Periodic Inspection Program. The AMR line items cite generic note G. The AMR line items also cite plant-specific note 3, indicating that the air with steam or water leakage environment is applicable to local areas within containment that are exposed to potential service water leakage or spray and that plant operating experience has shown that components in this environment exhibit aging effects similar to those that would be experienced in an outdoor air environment.

The staff reviewed the applicant's ASME Section XI, Subsection IWE; 10 CFR Part 50, Appendix J; Structures Monitoring; and Periodic Inspection programs and its evaluations are documented in SER Sections 3.0.3.2.13, 3.0.3.1.18, 3.0.3.2.15, and 3.0.3.3.2, respectively. The staff finds the applicant's proposed programs acceptable to manage aging for these components because each program or combination of programs includes detailed visual inspections to detect loss of material for stainless steel components.

The staff's evaluation for stainless steel bolting components exposed to indoor air, which are being managed for loss of material by the Bolting Integrity Program and loss of preload due to self-loosening by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs or the Structures Monitoring Program and cite generic note H, is documented in SER Section 3.1.2.3.1.

In LRA Table 3.5.2-3, the applicant stated that stainless, galvanized, carbon, and low-alloy steel bolting; galvanized steel cable trays, conduits, and tube tracks; carbon steel concrete embedments, pipe whip restraints, jet impingement shields, and all structural steel components; and carbon and galvanized steel panels, racks, cabinets, other enclosures, and miscellaneous components exposed to air with steam or water leakage are being managed for loss of material due to general, pitting, and crevice corrosion by the Structures Monitoring Program. The AMR line items cite generic note G. The applicant also stated that stainless steel bolting exposed to indoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line item cites generic note H for this item.

The staff reviewed the applicant’s Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff noted that the Structures Monitoring Program manages loss of preload or loss of material by conducting visual inspections of exposed bolting surfaces to determine if there is any loss of material, loose nuts, missing bolts, or other indications of aging. The staff finds the applicant’s management of the stainless, galvanized, carbon, or low-alloy steel components exposed to air with steam or water leakage or outdoor air acceptable because: (1) it includes visual inspections targeted at identifying loss of material and loss of preload and (2) has incorporated industry guidance from EPRI TR-104213 regarding proper selection of bolting materials, lubricants, and installation torque to prevent and mitigate loss of preload and loss of material, which is consistent with the GALL Report recommendations for these aging effects.

In LRA Table 3.5.2-3, the applicant stated that carbon steel penetration sleeves, cap plates, liner, liner anchors, and integral attachments exposed to air with steam or water leakage are being managed for loss of material due to general, pitting, and crevice corrosion by the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program. The AMR line items cite generic note G.

The staff reviewed all items in the GALL Report where the component is steel containment liner or penetration components and noted that there are GALL Report items for steel penetration sleeves (GALL Report item II.A3-1) and liner components (GALL Report item II.A2-11) exposed to indoor air or treated water that recommend managing loss of material using both GALL AMP XI.SI, “ASME Section XI, Subsection IWE,” and GALL AMP XI.S4, “10 CFR Part 50, Appendix J.” The staff also notes that air with steam or water leakage is similar to the indoor air or treated water environments discussed in the GALL Report for these components and, therefore, the GALL Report recommended programs are appropriate for these components.

The staff reviewed the applicant’s ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.18, respectively. The staff noted that the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program manage loss of material using visual and volumetric examinations and leak rate testing to ensure no loss of intended functions. The staff finds the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program acceptable to manage loss of material for these carbon steel components exposed to air with steam or water leakage because they include visual examinations appropriate for these components and are consistent with the GALL Report recommendations for managing this aging effect for these components.

In LRA Table 3.5.2-3, the applicant stated that elastomer moisture barriers (caulking, flashing, and other sealants) and seals and gaskets exposed to air with borated water leakage have an aging effect of loss of sealing due to deterioration that will be managed by a combination of the ASME Section XI, Subsection IWE Program and the 10 CFR Part 50, Appendix J Program. The

AMR line item cites generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed all AMR results in the GALL Report where the component type is elastomer seals, gaskets, and moisture barriers and confirmed that there are no entries for this component and material combination where the environment is air with borated water leakage.

The staff reviewed the applicant's ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.18, respectively. In its review of the ASME Section XI, Subsection IWE Program and the 10 CFR Part 50, Appendix J Program, the staff noted that visual inspection of moisture barriers are performed in accordance with the requirements of ASME Code Section XI, Subsection IWE and adequate leak tightness of containment seals and gaskets is confirmed with integrated leakage rate tests in accordance with the requirements of 10 CFR 50, Appendix J. The staff noted that this is consistent with the GALL Report recommendations for aging management of elastomer seals, gaskets, and moisture barriers exposed to air-indoor, uncontrolled, or air-outdoor (item II.A3-7). The staff also noted that inspections and tests performed to detect age-related degradation of elastomer seals, gaskets, and moisture barriers exposed to air-indoor, uncontrolled, or air-outdoor will be equally capable of detecting age-related degradation in the same components/material exposed to air with borated water leakage. Because the applicant's proposed AMP for elastomer seals, gaskets, and moisture barriers exposed to air with borated water leakage is capable of detecting age-related degradation for this component, material, and environment combination and implements corrective action in accordance with the requirements of ASME Code Section XI, Subsection IWE and the applicant's corrective action program, the staff finds the applicant's AMR results for this component, material, and environment combination that is not in the GALL Report to be acceptable.

For component type "bolting (containment closure)," the applicant stated that stainless steel bolting in an indoor air environment is managed for loss of preload/self-loosening by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs. This item references note H and plant-specific note 1 which states, "ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J are the applicable aging management program[s] for this component." The staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation because: (1) the ASME Section XI, Subsection IWE Program conducts general and detailed visual examinations and augmented inspections for evidence of aging effects that could affect leak tightness of the containment structure and includes the pressure-retaining bolting; and (2) the 10 CFR Part 50, Appendix J Program provides for detection of age-related degradation of components comprising the containment pressure boundary exposed to air environments due to aging effects such as loss of leak tightness, loss of material, or loss of preload in various systems penetrating containment. The staff's review of the applicant's ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs is documented in SER Sections 3.0.3.2.13 and 3.0.3.1.18, respectively. The staff finds that the applicant addressed the AERM adequately.

For component type "concrete interior," the applicant stated that reinforced concrete in an air with steam or water leakage environment is managed for increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack. This item references generic note G and plant-specific note 3. Plant-specific note 3 states, "Air with [a] steam or water leakage environment is applicable to local areas inside containment that are exposed to potential service water leakage or spray. Plant operating experience showed that metal components in this environment exhibit aging effects observed in [an] Air-Outdoor environment." The applicant stated that these components have the intended functions of either HELB/MELB shielding, missile barrier, shelter/protection, shielding, or structural support and are examined using the Structures Monitoring Program as the primary AMP. The staff's review of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. Since the Structures Monitoring Program inspects concrete based on guidance in ACI 201.1R to detect indications of increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel, the staff finds that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

For component type "steel components (sump screen)" in an air with steam or water leakage environment, the applicant stated that the stainless steel material is managed for loss of material due to pitting and crevice corrosion. This item references generic note G and plant-specific note 3 which states, "Air with [a] steam or water leakage environment is applicable to local areas inside containment that are exposed to potential service water leakage or spray. Plant operating experience showed that metal components in this environment exhibit aging effects observed in [an] Air-Outdoor environment." The applicant stated that this component has an intended function of filter and is examined using the Periodic Inspection Program as the primary AMP. The staff's review of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The Periodic Inspection Program includes provisions for periodic visual inspections of stainless steel components in an air with steam or water leakage environment to detect aging effects of loss of material and reduction of heat transfer. The applicant noted that the visual inspections are conducted on a 10-year inspection frequency that has been established based on plant and industry operating experience. The staff agrees that the Periodic Inspection Program is an appropriate AMP to address this AERM; however, since the intended function of the component is to act as a filter and other programs such as GALL AMP XI.M20, "Open-Cycle Cooling Water System," perform inspections annually and during refueling outages, it is unclear to the staff that an inspection interval of 10 years will be adequate to address the AERM. By letter dated June 7, 2010, the staff issued RAI 3.5.2.3-02 to address this issue.

In its response dated July 8, 2010, the applicant stated that the sump screen was listed as being in an air with steam or water leakage environment based on operating experience with service water leakage inside containment. The applicant further stated that the Periodic Inspection Program includes a procedure to inspect the component after any leakage events. The applicant explained that since the corrosive environment created by possible service water leakage is promptly addressed, no degradation is expected and the 10-year frequency is adequate.

The staff reviewed the applicant's response and noted that the possible corrosive air with leakage environment is event driven and is promptly addressed after leakage events. The staff noted that the leakage is cleaned up and the affected components are inspected for degradation. Since the components are inspected after events that could lead to corrosive environments, the staff finds the default 10-year frequency acceptable. Based on its review of the applicant's response, the staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.3-02 is resolved.

For component type "coating" in either an indoor air or air with borated water environment, the applicant stated that the paint material is managed for cracking, blistering, flaking, peeling, and delamination. This item references generic note J. The applicant stated that this component has an intended function of maintaining adhesion and is examined using the Protective Coating Monitoring and Maintenance Program and the Boric Acid Corrosion Program as the primary AMPs. The staff's evaluations of the applicant's Protective Coating Monitoring and Maintenance Program and the Boric Acid Corrosion Program are documented in SER Sections 3.0.3.1.19 and SER Sections 3.0.3.1.4, respectively. The Protective Coating Monitoring and Maintenance Program manages cracking, blistering, flaking, peeling, and delamination of Service Level I coatings subjected to an indoor air environment in the containment structure. Visual inspections are performed on all accessible areas of the containment during each refueling outage by qualified individuals knowledgeable in nuclear coatings. More thorough inspections of suspect areas are conducted and, when appropriate, additional testing may be done to characterize the severity of observed deficiencies. The Protective Coating Monitoring and Maintenance Program is consistent with coating monitoring requirements in RG 1.54 (Revision 1) and GL 98-04 and follows guidelines in ASTM D 5163-05(a). The Boric Acid Corrosion Program manages cracking, blistering, flaking, peeling, and delamination in an environment of air with borated water and includes provisions to identify, inspect, examine, and evaluate leakage, as well as initiate corrective action. Visual examinations are conducted in locations where leakage is detected, as well as adjacent locations that may be affected by the observed leakage. The examinations inside containment are performed during each refueling outage in accordance with the requirements of GL 88-05. The staff finds that the applicant has committed to an appropriate AMP for the period of extended operation because: (1) the Protective Coating Monitoring and Maintenance Program is used to verify coating adhesion and thus prevent blockage of the suction strainers, and (2) the Boric Acid Corrosion Program is used to manage loss of material due to boric acid corrosion. The staff finds that the applicant addressed the AERM adequately.

For component type "insulation (liner plate)" in an indoor air environment, the applicant stated that asbestos having an intended function of insulation does not have AERMs. This item references generic note J and plant-specific note 14 which states:

> Asbestos is a mineral fiber. The asbestos material located indoors and subject to an air-indoor environment is not subject to significant aging effects. Asbestos materials do not experience aging effects unless exposed to temperatures, radiation, or chemicals capable of attacking specific inorganic chemical composition. Asbestos materials are selected for compatibility with the environment during design. Asbestos material in this non-aggressive air environment is not expected to experience significant aging effects. This is consistent with plant operating experience.

The LRA states that the lower portion of the containment steel liner is largely covered by the liner insulation and stainless steel lagging and that in 2008, four insulation panels and lagging were removed in Unit 1 to permit inspection of the steel liner plate and moisture barrier which revealed no degradation of moisture barrier or significant liner corrosion. Since the LRA states that insulation and lagging will be removed at sample locations and the liner will be examined in accordance with ASME Code Section XI, Subsection IWE requirements both prior to the period of extended operation and every 10 years thereafter, the staff finds that potential degradation of the insulation would be identified in conjunction with the planned ASME Code Section XI, Subsection IWE inspections of the liner plate and a separate AMP is not required.

For component type "moisture barrier (caulking, flashing, and other sealants)" in an air with borated water environment, the applicant stated that elastomers having an intended function of water-retaining boundary are managed for loss of sealing/deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and gaskets) by the ASME Section XI, Subsection IWE Program. This item references generic note G. The staff's evaluation of the applicant's ASME Section XI, Subsection IWE Program is documented in SER Section 3.0.3.2.13. The staff finds that the applicant has committed to an appropriate AMP for the period of extended operation because: (1) the ASME Section XI, Subsection IWE Program performs visual inspections for evidence of aging effects that could affect loss of sealing of accessible portions of the moisture barrier, and (2) the program has been enhanced to require 100 percent visual inspection of the moisture barrier at the junction between the containment concrete floor and the containment liner to the extent practical both prior to the period of extended operation and every 10 years thereafter (Commitment No. 28). The staff finds that the applicant addressed the AERM adequately.

For component type "piles (heavy equipment platform foundation)," the applicant stated that concrete encased in steel and having an intended function of structural support does not have AERMs. This item references generic note G and plant-specific note 8 which states, "Concrete encased in steel is protected from environments that promote age related degradations." The LRA states that degradation of piles or foundation mats will manifest in settlement distortion or cracking and accessible concrete examinations will detect cracks and distortion of the structures. Studies have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the oxygen deficiency in soil at a few feet below grade. Piles driven into disturbed soil have been shown to experience only minor to moderate corrosion. In either case, the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557. Since the concrete is encased in steel and, therefore, in a protected environment and containment-related structures are monitored under the Structures Monitoring Program for cracks and distortion due to increased stress levels from settlement, the staff finds that a separate AMP for concrete piles encased in steel is not required. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant addressed the AERM adequately.

For component type "transfer tube bellows (excludes containment penetration bellows)" in a treated borated water environment, the applicant stated stainless steel having an intended function of water-retaining boundary is managed for cumulative fatigue damage/fatigue by TLAA. This item references generic note G and plant-specific note 15 which states, "The TLAA designation in the Aging Management Program column indicates fatigue of this component is evaluated in Section 4.5." LRA Section 3.5.2.2.1.6 states that a TLAA evaluation for the transfer tube bellows was performed. The stainless steel transfer tube bellows are not part of the containment penetration bellows and are not part of the containment pressure boundary, but are a water-retaining boundary associated with the reactor cavity in the containment and the transfer pool in the fuel handling building. The TLAA evaluation shows that the projected number of cycles for 60 years is less than the design cycles. Thus, cracking of transfer tube bellows due to cyclic loading is not expected to occur through the period of extended operation. The TLAA is evaluated in accordance with 10 CFR 54.21(c). Evaluation of this TLAA is discussed in SER Section 4.5, "Fuel Transfer Tube Bellows Design Cycles."

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 Containments, Structures, and Component Supports – Fire Pump House – Summary of Aging Management Evaluation – LRA Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for the fire pump house component groups.

The staff's evaluation for stainless steel bolting components exposed to indoor air, which are being managed for loss of material by the Bolting Integrity Program and loss of preload due to self-loosening by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs, or the Structures Monitoring Program and cite generic note H, is documented in SER Section 3.1.2.3.1.

In LRA Tables 3.5.2-4, 3.5.2-7, 3.5.2-10, 3.5.2-13, 3.5.2-16, and 2.5.2-17, the applicant stated that aluminum bolting exposed to either indoor or outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H for this item, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because aluminum bolting will have comparable loss of preload as other bolting material. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the above program acceptable because the Structures Monitoring Program uses guidance from EPRI TR-104213 for ensuring that loss of preload is appropriately managed, which is consistent with the GALL Report for management of bolting.

The staff's evaluation for grout penetration seals exposed to an indoor or outdoor air environment, which are being managed for cracking or loss of material by the Structures Monitoring Program with generic note F, is documented in SER Section 3.5.2.3.1.

The staff's evaluation for interior concrete of concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.5 Containments, Structures, and Component Supports – Fuel Handling Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-5

The staff reviewed LRA Table 3.5.2-5, which summarizes the results of AMR evaluations for the fuel handling building component groups.

In LRA Table 3.5.2-5, the applicant stated that the stainless steel transfer tube penetration bellows exposed to treated borated water are being managed for cumulative fatigue damage by a TLAA. The AMR line item cites generic note G. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1) and the staff's evaluation of the TLAA for this item is documented in SER Section 4.5.

In LRA Table 3.5.2-5, the applicant stated that stainless steel penetration bellows components exposed to groundwater or soil are being managed for cumulative fatigue damage by a TLAA. The AMR line item cites generic note G. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1) and the staff's evaluation of the TLAA for this item is documented in SER Section 4.5.

In LRA Table 3.5.2-5, the applicant stated that stainless steel transfer tube penetration bellows exposed to groundwater or soil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Buried Non-Steel Piping Inspection Program. The AMR line items cite generic note H.

The staff reviewed the applicant's Buried Non-Steel Piping Inspection Program and its evaluation is documented in SER Section 3.0.3.3.4. The staff finds the applicant's program acceptable to manage aging for these components because it includes focused visual inspections for loss of material when the components are excavated for any reason or at least one inspection will be performed within the 10 years prior to the period of extended operation and one during the first 10 years of extended operation.

For component type "penetration sleeves," the applicant proposed to assign carbon steel to the Periodic Inspection Program to manage the aging effect of loss of material due to pitting and crevice corrosion in a treated borated water environment. This item references generic note G. The applicant stated that this component has the intended function of water-retaining boundary. The Periodic Inspection Program includes provisions for periodic visual inspections of stainless steel, aluminum, copper alloy, and elastomer components in a treated borated water environment to detect aging effects of loss of material and reduction of heat transfer. The applicant noted that the visual inspections are conducted on a 10-year inspection frequency that has been established based on plant and industry operating experience. The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. During the staff's review of the Periodic Inspection Program, it was noted that carbon steel components do not appear to be addressed by this AMP and a 10-year inspection frequency is used. The staff is unclear how the Periodic Inspection Program will be used to address the AERM and that the inspection interval is frequent enough to detect degradation in a timely manner during the period of extended operation. By letter dated June 7, 2010, the staff issued RAI 3.5.2.3-03 to address this issue.

In its response dated July 8, 2010, the applicant explained that the penetration sleeves are the carbon steel sleeves for the fuel transfer tubes, where the sleeves extend into the fuel transfer pools. The applicant further explained that the sleeves are coated with a three part epoxy system which is resistant to borated water based on testing of similar epoxy systems by the same manufacturer. The applicant also stated that based upon data in EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," the corrosion rate of carbon steel in borated water is 0.02 inch per year or less. The applicant further stated that the sleeve is nominally 1 inch thick. Based upon these facts, the applicant concluded the 10-year inspection frequency was adequate.

The staff reviewed the applicant's response and found it acceptable. The staff noted that the components are coated by an epoxy system. The staff also noted that corrosion of the penetration sleeves would be visible as a rust product which would be identified during a visual inspection. The staff's review did not identify any plant-specific operating experience that would indicate a 10-year inspection interval was inadequate. In addition, the components are included within the scope of the One-Time Inspection and Water Chemistry programs which provide additional assurance that any degradation would be captured and identified in a timely manner. Since the Periodic Inspection Program includes visual inspections of the penetration sleeves, conducted with an acceptable frequency, the staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.3-03 is resolved.

For component type "steel components (leak chase system)," the applicant proposed to assign carbon steel to either the One-Time Inspection Program or Water Chemistry Program to manage the aging effect of loss of material due to general, pitting, and crevice corrosion in a treated borated water (internal or external) environment. This item references generic note G and plant-specific note 4 which states:

> Plant operating experience showed that treated borated water leakage through indications in the liner plate welds could overflow the leak chase channels if the drain lines are clogged and come into contact with reinforced concrete, exterior surfaces of the stainless steel liner, and the leak chase channel system. The leak chase channels drain lines will be monitored for blockage and cleared as required to ensure proper drainage is maintained.

The applicant stated that this component has the intended function of direct flow. The staff's evaluations of the applicant's One-Time Inspection Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.11 and 3.0.3.1.2, respectively. The Water Chemistry Program manages the effects of cracking, loss of material, reduction of neutron-absorbing capacity, and reduction of heat transfer for RCS and related auxiliary systems containing treated water, reactor coolant, treated borated water, and steam, including the primary side of SGs. This program includes periodic sampling of primary and secondary water for the known detrimental contaminants (e.g., chlorides, fluorides, DO, and sulfates). The Water Chemistry Program does not provide for detection of aging effects. The One-Time Inspection Program is used to confirm the effectiveness of the Water Chemistry Program to manage loss of material, cracking, and reduction of heat transfer aging effects of steel in treated borated water. The One-Time Inspection Program is a condition monitoring program for identification of aging effects and evaluation of the need for follow-up examinations to monitor progression of age-related degradation with inspections scheduled within 10 years prior to the period of extended operation. In the LRA, it notes that the SFPs at Salem have experienced leakage of borated water that has migrated through small cracks in the concrete to reach the seismic gap between the containment structure and fuel handling building. Materials such as boric acid and minerals have accumulated in the leak collection and detection system that restricted normal drainage of fluid. Borated water has accumulated between the liner and concrete and migrated to other locations through penetrations, construction joints, and cracks. The seismic gap was confirmed to contain water with radionuclides characteristic of the SFP water and leakage into the seismic gap has continued. Leakage into the telltale drains is occurring at a rate of about 100 gpd. Based on operating experience provided in the LRA, it is unclear to the staff how this AERM will be adequately addressed through the One-Time Inspection and Water Chemistry programs. By letter dated June 7, 2010, the staff issued RAI 3.5.2.3-04 to address this issue.

In its response dated July 8, 2010, the applicant stated that this component is also monitored by the Structures Monitoring Program. The Structures Monitoring Program is being enhanced to ensure that the intended function of directing flow is maintained by monitoring the telltale leakage and inspecting the system to ensure no blockage. This inspection will be performed on an interval not to exceed 18 months. The applicant explained that this inspection would be capable of detecting a buildup of corrosion products. The applicant also explained that based upon data in EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," the corrosion rate of carbon steel in borated water is 0.02 inch per year or less. The applicant stated that the proposed AMPs, including the 18-month frequency inspections conducted by the Structures Monitoring Program, are adequate.

The staff reviewed the applicant's response and found it acceptable. Although the staff does not necessarily agree with the corrosion rate quoted by the applicant, the staff noted that the applicant has enhanced the Structures Monitoring Program to monitor the telltale leakage and to inspect the system on an 18-month frequency. These activities provide reasonable assurance that degradation of the leak chase system will be detected prior to loss of intended function. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. Since the applicant has committed to inspections of the leak chase system, the staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.3-04 is resolved.

The staff's evaluation for grout penetration seals exposed to an indoor or outdoor air environment, which are being managed for cracking or loss of material by the Structures Monitoring Program with generic note F, is documented in SER Section 3.5.2.3.1.

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).

3.5.2.3.6 Containments, Structures, and Component Supports – Office Buildings – Summary of Aging Management Evaluation – LRA Table 3.5.2-6

The staff reviewed LRA Table 3.5.2-6, which summarizes the results of AMR evaluations for the office buildings component groups.

In LRA Tables 3.5.2-6, 3.5.2-10, 3.5.2-12, 3.5.2-13, 3.5.2-15, 3.5.2-16, and 3.5.2-17, the applicant stated that galvanized, carbon, or low-alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff noted that the Structures Monitoring Program manages loss of preload or loss of material by conducting visual inspections of exposed bolting surfaces to determine if there is any loss of material, loose nuts, missing bolts, or other indications of aging. The staff finds the applicant's program acceptable to manage aging for these components because: (1) it includes visual inspections targeted at identifying loss of material and loss of preload and (2) has incorporated industry guidance from EPRI TR-104213 regarding proper selection of bolting materials, lubricants, and installation torque in order to prevent and mitigate loss of preload, which is consistent with the GALL Report recommendations for managing this aging effect.

The staff's evaluation for interior concrete of concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL

Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.7 Containments, Structures, and Component Supports – Penetration Areas – Summary of Aging Management Evaluation – LRA Table 3.5.2-7

The staff reviewed LRA Table 3.5.2-7, which summarizes the results of AMR evaluations for the penetration areas component groups.

The staff's evaluation for aluminum bolting exposed to indoor and outdoor air, which is being managed for loss of preload by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.4.

The staff's evaluation for interior concrete of concrete filled steel hatches/plugs, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.1.

3.5.2.3.8 Containments, Structures, and Component Supports – Pipe Tunnel – Summary of Aging Management Evaluation – LRA Table 3.5.2-8

The staff reviewed LRA Table 3.5.2-8, which summarizes the results of AMR evaluations for the pipe tunnel component groups.

In LRA Table 3.5.2-8, the applicant stated that stainless steel structural bolting components exposed to outdoor air are not being managed for loss of preload due to self-loosening. The AMR line item cites generic note G. The AMR line item also cites plant-specific note 2, which indicates that no AMP is required because the nuts on the bolting are tack welded.

The staff finds that the applicant's determination that no AMP is required to manage loss of preload for this component acceptable because bolts with tack welded nuts would not be expected to experience loss of preload and the components are being managed for loss of material in another line. By letter dated June 7, 2010, the staff issued RAI 3.5.2.3-05 regarding the lack of an AMP for this component. This RAI was issued in error. The topic was discussed during a conference with the applicant on May 19, 2010, during which the applicant explained that the bolts were tack welded and the staff agreed no AMP was necessary and, therefore, no RAI was necessary.

The staff's evaluation for grout penetration seals exposed to an air-indoor, air-outdoor, or groundwater/soil environment, which are being managed for cracking or loss of material by the Structures Monitoring Program with generic note F, is documented in SER Section 3.5.2.3.1.

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).

3.5.2.3.9 Containments, Structures, and Component Supports – Piping and Component Insulation Commodity Group – Summary of Aging Management Evaluation – LRA Table 3.5.2-9

The staff reviewed LRA Table 3.5.2-9, which summarizes the results of AMR evaluations for the piping and component insulation commodity group component groups.

For component type "insulation," the applicant stated that "Min-K," calcium silicate, ceramic fiber, fiberglass, and NUKON in an air-indoor, air-outdoor, or air with borated water leakage environment having an intended function of thermal insulation does not have AERMs and does not require an AMP. The applicant also stated for component type "insulation jacketing (includes wire mesh, straps, clips)," the fiberglass blanket in an air-indoor or air with borated water leakage environment having an intended function of either shelter/protection or structural support also does not have AERMs. Both of these items reference generic note J and plant-specific note 1 which states, "Based on plant operating experience, there are no aging effects requiring management for this material and environment combination." The LRA also states that the purpose of piping and component insulation is to improve thermal efficiency, minimize heat loads on the HVAC systems, provide for personnel protection, prevent freezing of heat traced piping, or protect against sweating of cold piping and components. Insulation located in areas with safety-related equipment is designed to protect nearby safety-related SSC equipment from overheating and maintain its structural integrity during postulated design-basis seismic events. Insulation within the containment structure is required to maintain its integrity to prevent exceeding the analyzed debris limit for the containment sump screens. The insulation and insulation jacketing (includes wire mesh, straps, clips) perform an intended function and are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff reviewed the GALL Report and verified that it includes no AMR item for this component, material, and environment combination. Since the piping and component insulation commodity group is not classified as a safety-related commodity and the thermal insulation is typically passive and long-lived, the staff concludes there are no applicable AERMs for the materials or environments identified in the table and that the applicant need not credit an AMP.

In LRA Table 3.5.2-9, the applicant stated that stainless steel insulation and insulation jacketing components exposed to air with steam or water leakage are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection Program. The AMR line items cite generic note G.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff finds the applicant's program acceptable to manage aging for these components because it includes periodic visual inspections to detect loss of material, which is appropriate for these components.

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).

3.5.2.3.10 Containments, Structures, and Component Supports – Station Blackout Yard Buildings – Summary of Aging Management Evaluation – LRA Table 3.5.2-10

The staff reviewed LRA Table 3.5.2-10, which summarizes the results of AMR evaluations for the SBO yard buildings component groups.

The staff's evaluation for galvanized carbon or low-alloy steel bolting exposed to outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program and with generic note H, is documented in SER Section 3.5.2.3.6.

The staff's evaluation for aluminum bolting exposed to indoor and outdoor air, which is being managed for loss of preload by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.4.

3.5.2.3.11 Containments, Structures, and Component Supports – Service Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-11

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the service building component groups.

The staff's evaluation for interior concrete of concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.3.

3.5.2.3.12 Containments, Structures, and Component Supports – Service Water Accumulator Enclosures – Summary of Aging Management Evaluation – LRA Table 3.5.2-12

The staff reviewed LRA Table 3.5.2-12, which summarizes the results of AMR evaluations for the service water accumulator enclosures component groups.

The staff's evaluation for galvanized, carbon, or low-alloy steel bolting exposed to outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.6.

3.5.2.3.13 Containments, Structures, and Component Supports – Service Water Intake – Summary of Aging Management Evaluation – LRA Table 3.5.2-13

The staff reviewed LRA Table 3.5.2-13, which summarizes the results of AMR evaluations for the service water intake component groups.

In LRA Table 3.5.2-13, for component type "ice barrier/marine dock bumper" in either an air-outdoor or water flowing environment, the applicant stated that the treated wood is managed for change in material properties, loss of material due to insect damage, and moisture damage by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. This item references generic note J. The LRA states that these components have the intended function of shelter/protection and are in the form of steel shapes and treated wood that are designed such that surface ice jams will not damage the service water intake structure. The design of the ice barriers also includes marine dock bumpers. The LRA also states that the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented through the Structures Monitoring Program. The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring programs are documented in SER Sections 3.0.3.2.15 and 3.0.3.2.16, respectively. The staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation because the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program: (1) has been enhanced to monitor change in material properties and loss of material due to insect damage and moisture damage and (2) is implemented through the Structures Monitoring

Program, which conducts visual inspections on a frequency not to exceed 5 years. The staff finds that the applicant addressed the AERM adequately.

In LRA Tables 3.5.2-13 and 3.5.2-15, the applicant stated that stainless steel structural bolting exposed to raw water, indoor air, and outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.15. The staff finds the applicant's program acceptable to manage aging for these components because: (1) it includes periodic visual inspections for missing or loose bolts in order to detect loss of preload and (2) has incorporated the guidance in EPRI TR-104213 regarding proper selection, lubrication, and installation of bolting in order to prevent loss of preload from occurring.

The staff's evaluation for galvanized, carbon, or low-alloy steel bolting exposed to outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.6.

The staff's evaluation for aluminum bolting exposed to indoor and outdoor air, which is being managed for loss of preload by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.4.

For component type "bolting (structural)" in a raw water environment, the applicant stated that stainless steel bolting having an intended function of structural support is managed for loss of preload due to self-loosening by the Structures Monitoring Program Program. This item references generic note G and plant-specific note 1 which states:

> Based on industry standards and operating experience[,] age related loss of preload/self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload/ self-loosening of structural bolting is not significant and will not impact structural intended functions. Nevertheless, loss of preload/self-loosening will be monitored through the Structures Monitoring Program.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. The staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation because: (1) the Structures Monitoring Program monitors exposed surfaces of bolting for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload; and (2) the program incorporates procedures based on EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. The staff finds that the applicant addressed the AERM adequately.

For component types "concrete (below grade exterior)" and "concrete foundation" in a groundwater/soil environment, the applicant stated that the reinforced concrete having the intended function of either flood barrier, shelter/protection, or structural support is managed for cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. This item references note H and plant-specific note 3 which states, "The aging effects and Aging Management Program identified for this material/environments combination are consistent with industry guidance." The LRA states that the applicant's Structures Monitoring Program is used to implement the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.15, respectively. The staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation because the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program: (1) has been enhanced to visually inspect water-control structures; (2) is implemented through the Structures Monitoring Program, which conducts visual inspections on a frequency not to exceed 5 years; and (3) is based on guidance provided in RG 1.127 and ACI 349.3R. The staff finds that the applicant addressed the AERM adequately.

For component type "concrete (interior)" in a water flowing environment, the applicant stated that the reinforced concrete having an intended function of either direct flow or structural support is managed for cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel and increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack by the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. This item references note H and plant-specific note 3 which states, "The aging effects and Aging Management Program identified for this material/environments combination are consistent with industry guidance." The LRA states that the applicant's Structures Monitoring Program is used to implement the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and the Structures Monitoring programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.15, respectively. The staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation because the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program: (1) has been enhanced to visually inspect water-control structures; (2) is implemented through the Structures Monitoring Program, which conducts visual inspections on a frequency not to exceed 5 years; and (3) is based on guidance provided in RG 1.1.27 and ACI 349.3R. The staff finds that the applicant addressed the AERM adequately.

For component type "penetration seals," the applicant proposed to assign grout to the Structures Monitoring Program to manage the aging effect of cracking and shrinkage in an air-indoor, air-outdoor, or water flowing environment. This item references note F and plant-specific note 5 which states, "Based on industry standards and guidelines, grout is susceptible to cracking due to shrinkage in this environment. However, shrinkage cracking occurs early in plant life and is not expected to be significant for the extended period of operation. Nevertheless, the aging effect will be monitored through the Structures Monitoring Program." The applicant stated that these components have the intended function of flood barrier and are examined using the Structures Monitoring Program as the primary AMP. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15. Since the Structures Monitoring Program has been enhanced to inspect penetration seals for indications of concrete deterioration or distress including evidence of leaching, loss of material, cracking, and loss of bond as defined in ACI 201.1R at a frequency of 5 years, the staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

For component type “penetration seals,” the applicant proposed to assign grout to the Structures Monitoring Program to manage the aging effect of loss of material (spalling, scaling), cracking due to freeze-thaw, increase in porosity and permeability, and aggressive chemical attack in either an air-outdoor, groundwater/soil, or water flowing environment. This item references note F and plant-specific note 3 which states, “The aging effects and aging management program identified for this material/environments combination are consistent with industry guidance.” The applicant stated that these components have an intended function of flood barrier and are examined using the Structures Monitoring Program as the primary AMP. The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.15. Since the Structures Monitoring Program has been enhanced to inspect penetration seals for indications of concrete deterioration or distress including evidence of leaching, loss of material, cracking, and loss of bond as defined in ACI 201.1R at a frequency of 5 years, the staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.14 Containments, Structures, and Component Supports – Shoreline Protection and Dike – Summary of Aging Management Evaluation – LRA Table 3.5.2-14

The staff reviewed LRA Table 3.5.2-14, which summarizes the results of AMR evaluations for the shoreline protection and dike component groups.

For component type “earthen water-control structures/embankments (dikes)” having an intended function of flood barrier, the applicant proposed to assign soil, rip-rap, sand, and gravel to the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to manage the aging effects of loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage in an air-outdoor environment. This item references generic note G and plant-specific note 2 which states, “Based on industry standards and guidelines, earthen water-control structures are susceptible to loss of material and loss of form in [an] air-outdoor environment.” The LRA also states that the applicant’s RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is implemented through the Structures Monitoring Program. The staff’s evaluations of the applicant’s RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.17, respectively. The staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation because the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program: (1) is based on guidance provided in RG 1.127, which addresses aging effects noted above; and (2) is implemented through the Structures Monitoring Program, which conducts visual inspections on a frequency not to exceed 5 years. The staff finds that the applicant addressed the AERM adequately.

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).

3.5.2.3.15 Containments, Structures, and Component Supports – Switchyard – Summary of Aging Management Evaluation – LRA Table 3.5.2-15

The staff reviewed LRA Table 3.5.2-15, which summarizes the results of AMR evaluations for the switchyard component groups.

The staff's evaluation for stainless steel structural bolting exposed to raw water, indoor air, and outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.13.

The staff's evaluation for galvanized, carbon, or low-alloy steel bolting exposed to outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.6.

In LRA Table 3.5.2-15, the applicant stated that polyvinyl chloride (PVC) conduit exposed to concrete has no AERM and that for this component, material, and environment combination, no AMP is needed. The AMR line items cite generic note J, indicating that neither the component nor the material and environment combination is evaluated in the GALL Report.

The staff reviewed the GALL Report and confirmed that neither the conduit nor PVC is included therein. This review confirmed that the applicant's use of generic note J is acceptable.

For these AMR results, the applicant also cited plant-specific note 3, stating that the PVC is encased in concrete and has no aging effects for the identified environment. The staff notes that given the component's switchyard location with potential proximity to high-voltage equipment or exposure to sunlight, PVC components could be susceptible to known stressors such as ultraviolet light or ozone. The staff finds the applicant's determination that no AMP is needed acceptable because given that the PVC pipe is encased in concrete, the material will not be exposed to significant ultraviolet light or ozone.

The staff's evaluation for interior concrete of concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.16 Containments, Structures, and Component Supports – Turbine Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-16

The staff reviewed LRA Table 3.5.2-16, which summarizes the results of AMR evaluations for the turbine building component groups.

The staff's evaluation for galvanized, carbon, or low-alloy steel bolting exposed to outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.6.

The staff's evaluation for aluminum bolting exposed to indoor and outdoor air, which is being managed for loss of preload by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.4.

The staff's evaluation for grout penetration seals exposed to an indoor or outdoor air, or groundwater/soil environment, which are being managed for cracking or loss of material by the Structures Monitoring Program with generic note F, is documented in SER Section 3.5.2.3.1.

The staff's evaluation for interior concrete of concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.3.

3.5.2.3.17 Containments, Structures, and Component Supports – Yard Structures – Summary of Aging Management Evaluation – LRA Table 3.5.2-17

The staff reviewed LRA Table 3.5.2-17, which summarizes the results of AMR evaluations for the yard structures component groups.

The staff's evaluation for galvanized, carbon, or low-alloy steel bolting exposed to outdoor air, which is being managed for loss of preload due to self-loosening by the Structures Monitoring Program with generic note H, is documented in SER Section 3.5.2.3.6.

The staff's evaluation for interior concrete of concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.3.

The staff's evaluation for PVC conduit embedded in concrete, with no aging effect and no credited AMP and referencing generic note J, is documented in SER Section 3.5.2.3.15.

3.5.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls

This section documents the staff's review of the applicant's AMR results for the electrical and instrumentation and controls (I&C) components and component groups of the following:

- cable connections-metallic parts
- connector contacts for electrical connectors exposed to borated water leakage
- fuse holders (not part of a larger assembly): fuse holders-metallic clamp
- high-voltage insulators
- insulated cables and connections
- metal-enclosed bus
- switchyard bus 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 components and component groups. LRA Table 3.6.1, "Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL Report," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical components, I&C components, and component groups. The applicant stated that electrical penetrations are not subject to their own AMR in this section in that they are addressed: (1) as a TLAA in the EQ program, (2) as part of the insulated cables and connections commodity group, and (3) in the containment structure AMR (Table 3.5.2-3).

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 since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C 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 reviewed 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 has identified the appropriate GALL Report AMPs. 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 3.6.2.1.

The staff also reviewed 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 evaluations are documented in SER Section 3.6.2.2.

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 (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 EQ requirements (3.6.1-1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	Yes	TLAA	EQ is a TLAA (see SER Section 3.6.2.2.1)
Electrical cables, connections, and fuse holders (insulation) not subject to 10 CFR 50.49 EQ requirements (3.6.1-2)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Conductor insulation for electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (3.6.1-3)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Used in Instrumentation Circuits Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Conductor insulation for inaccessible medium-voltage (2 kV to 35 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (3.6.1-4)	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Connector contacts for electrical connectors exposed to borated water leakage (3.6.1-5)	Corrosion of connector contact surfaces due to intrusion of borated water	Boric Acid Corrosion	No	Boric Acid Corrosion	Consistent with the GALL Report
Fuse holders (not part of a larger assembly): fuse holders-metallic clamp (3.6.1-6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	No	Not applicable	Not applicable to Salem (see SER Section 3.6.2.3.1)
Metal-enclosed bus-bus, connections (3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal-Enclosed Bus	No	Metal Enclosed Bus	Consistent with the GALL Report (see SER Section 3.6.1-7)
Metal-enclosed bus-insulation, insulators (3.6.1-8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal-Enclosed Bus	No	Metal Enclosed Bus	Consistent with the GALL Report (see SER Section 3.6.1-8)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Metal-enclosed bus-enclosure assemblies (3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring	No	Not applicable	Not applicable to Salem (see SER Section 3.6.2.1.1)
Metal-enclosed bus-enclosure assemblies (3.6.1-10)	Hardening and loss of strength due to elastomer degradation	Structures Monitoring	No	Structures Monitoring Program	Consistent with the GALL Report
High-voltage insulators (3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific AMP is to be evaluated.	Yes	High Voltage Insulators	Consistent with the GALL Report (see SER Sections 3.6.2.2.2 and 3.6.2.3.1)
Transmission conductors and connections; switchyard bus and connections (3.6.1-12)	Loss of material due to wind-induced abrasion and fatigue; loss of conductor strength due to corrosion; 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 Salem (see SER Section 3.6.2.2.3)
Cable connections-metallic parts (3.6.1-13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Fuse holders (not part of a larger assembly)-insulation material (3.6.1-14)	None	None	NA	None	Consistent with the GALL Report

The staff's review of the electrical and I&C 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 components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results That Are 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 components:

- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Boric Acid Corrosion
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Enclosed Bus
- Structures Monitoring Program
- High Voltage Insulators

In LRA Table 3.6.2-1, the applicant summarizes AMRs for the electrical and I&C components and claimed that these AMRs are consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the report and for which the GALL 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 line item how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A through E indicating how the AMR is 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 reviewed the LRA to confirm that the applicant: (1) provided a brief description of the system, components, materials, and environments; (2) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (3) identified those aging effects for the electrical and I&C components that are subject to an AMR. On the basis of its review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.6.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's 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 indeed consistent with its AMRs. Therefore, 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).

3.6.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.6-1, item 3.6.1-9 addresses the aging effect of loss of material caused by the mechanisms of pitting and crevice corrosion for aluminum metal-enclosed bus enclosure assemblies exposed to air-indoor and states that there is no AERM and no AMP is recommended. The applicant referred to LRA Table 3.5.1, item 3.5.1-58. In LRA Table 3.5-1, item 3.5.1-58, the applicant stated that the material/environment combination for galvanized steel and aluminum support members, welds, bolted connections, and support anchorages to building structure exposed to indoor air has no aging effect/mechanism that requires aging management. The applicant also stated further that no AMPs are applicable to the aluminum items exposed to indoor air for the electrical commodities system associated with this item number. The GALL Report, Volume 2, Revision 1, item III.B5-2, which corresponds to Table 3.5.1, item 3.5.1-58, recommends that there is no aging effect or aging mechanism for aluminum exposed to air-indoor uncontrolled and that no AMP is recommended for this component group and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.6.1, item 3.6.1-11 addresses degradation of insulation quality due to the presence of any salt deposits and surface contamination and loss of material caused by mechanical wear due to wind blowing on transmission conductors. The GALL Report did not address or identify any aging effect of the cement and metal material pin inside high-voltage insulators. In LRA Table 3.6.2-1 under high-voltage insulators, the applicant claimed that cement and metal material have no aging effects and no AMP. 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.

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

In LRA Section 3.6.2.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the electrical and I&C components and provided information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ
- degradation of insulator quality due to salt deposits or surface contamination and loss of material due to mechanical wear
- 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 GALL Report recommends further evaluation, the staff reviewed the corresponding AMR items 3.6.1-11 and 3.6.1-12 in LRA Table 3.6.1. The staff also 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

In LRA Section 3.6.2.2.1, the applicant provided an evaluation of EQ TLAAs. SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA.

3.6.2.2.2 Degradation of Insulator Quality Due to Salt Deposits or Surface Contamination and Loss of Material Due to Mechanical Wear

LRA Section 3.6.2.2.2 addresses degradation of insulator quality due to salt deposits or surface contamination and loss of material due to mechanical wear. The applicant stated that the high-voltage insulators evaluated for Salem are those used to support in-scope, un-insulated, high-voltage electrical commodities such as switchyard bus. The supported commodities are those credited for supplying power to in-scope components for recovery of offsite power following an SBO. The majority of the insulators within the scope of license renewal at Salem are configured vertically and are designed with an increased creepage distance that is able to withstand "medium" pollution levels. Vertical insulators with increased creepage distance are less susceptible to flashover due to surface contamination.

The applicant also stated that Salem is located in a rural area, not near heavy industry that would provide a source for contaminants, and is not in close proximity to the Atlantic Ocean. The station is located at the end of the Delaware River (at the head of Delaware Bay), 50 miles from the Atlantic Ocean. Therefore, Salem is not considered to be a seacoast plant, where salt spray is prevalent. The applicant stated that site-specific operating experience has shown that flashover of insulators due to contamination from salt spray is an applicable aging mechanism that requires management. One plant-specific event occurred at Salem in September 2003, when Hurricane Isabel passed a considerable distance to the south and west of the site. Strong winds with gusts in excess of 60 mph caused switchyard insulators to become coated with salt. The applicant stated that it will implement a plant-specific High Voltage Insulators Program to detect the buildup of surface contamination on high-voltage insulators in the Salem switchyard.

The applicant stated that mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. There are no strain and suspension insulators within the scope of license renewal at Salem. Therefore, aging management activities for loss of material due to wear are not required for the period of extended operation.

The staff reviewed LRA Section 3.6.2.2.2 against SRP-LR Section 3.6.2.2.2, which states that degradation of insulator quality due to salt deposits or 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 staff noted various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. However, the buildup of surface contamination is gradual and in most areas such contamination is washed away by rain; the glazed insulator surface aids this contamination removal. Surface contamination can be a problem in areas where there is the greatest concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. Plant-specific operating experience at Salem has shown that flashover of insulators due to salt spray is an applicable aging mechanism that requires management. As described above, one plant-specific event occurred at Salem in September 2003, when Hurricane Isabel passed the site. Strong winds with gusts in excess of 60 mph cause switchyard insulators to become coated with salt deposit. The applicant proposed a plant-specific High Voltage Insulators Program to manage the buildup of salt deposit on high-voltage insulators. The staff evaluated this program in SER Section 3.0.3. The staff determined that this AMP is acceptable because visual inspection is appropriate to inspect surface contamination for salt deposit.

The staff noted that mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swinging is frequent enough, it could cause wear in the metal contact point of the insulator string and between an insulator and supporting hardware. At Salem, there are no strain and suspension insulators within the scope of license renewal. Therefore, the staff found that loss of material due to mechanical wear is not applicable to Salem.

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 line items that apply to LRA Section 3.6.2.2.2, 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).

3.6.2.2.3 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 addresses 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.

In LRA Section 3.6.2.2.3, the applicant stated that there are no transmission conductors and connections within the scope of license renewal at Salem. Therefore, aging management activities for 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 associated with transmission conductors and connections are not required for the period of extended operation.

The applicant also stated that the switchyard bus and connections evaluated for Salem are those credited for supplying power to in-scope components for recovery of offsite power following an SBO. The switchyard buses within the scope of this review are constructed of rigid 4-inch, schedule 80 aluminum pipe. The applicant also stated that switchyard buses at Salem are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components such as concrete footings and structural steel. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue is not an applicable aging mechanism. The applicant further stated that the Salem switchyard bus is not subject to an ocean environment or industrial air pollution. Salem is located in a rural area, not near heavy industry that would provide a source for contaminants, and is not in close proximity to the Atlantic Ocean. The station is located at the end of the Delaware River (at the head of Delaware Bay), 50 miles from the Atlantic Ocean. Therefore, Salem is not considered to be a seacoast plant, where salt spray is prevalent. Aluminum bus material does not experience any appreciable aging effects in this environment. Therefore, corrosion is not an applicable aging mechanism. The applicant also stated that switchyard bus connections employ good bolting practices consistent with the recommendations of EPRI 1003471, “Electrical Connector Application Guidelines.” The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued to avoid loss of preload, at the time of installation. The switchyard bus bolted connections are designed and installed using lock washers and stainless steel Belleville washers (not electroplated) that provide vibration absorption and prevent loss of preload. Therefore, the applicant concluded that oxidation and loss of preload are not applicable aging effects. The applicant further stated that transmission and distribution personnel perform normal maintenance activities on all portions of the switchyard, including switchyard bus and connections. These maintenance activities have not revealed significant aging effects or mechanisms associated with this equipment to date.

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3, which state 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.

In LRA Section 3.6.2.2.3, the applicant stated that there are no transmission conductors and connections within the scope of license renewal at Salem. During the audit of LRA, the staff reviewed the Salem offsite power for SBO and discussed with the plant technical staff. The staff confirmed that there are no transmission conductors and connections within the scope of license renewal at Salem. Therefore, the staff determined that loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion of the transmission conductor, and increased resistance of connection due to oxidation or loss of preload associated with transmissions and connections are not applicable for the period of extended operation.

The staff noted that the switchyard buses at Salem are connected to flexible conductors that do not swing and are supported by insulators and structural supports such as concrete footing and structural steel. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue is not an applicable aging mechanism. The design of switchyard bolted connections at Salem precludes torque relaxation and corrosion. The use of stainless steel Belleville washers is the industry standard to preclude torque relaxation. Salem design incorporates the use of Belleville washers on bolted electrical connections of dissimilar metals to compensate for temperature changes, maintain the proper torque, and prevent loosening. This method of assembly is consistent with the good bolting practices recommended by industry guidelines (EPRI TR-104213, "Bolted Joint Maintenance & Application Guide"). The bolted connections and washers are coated with an antioxidant compound (a grease-type sealant) prior to 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. This method of installation has been shown to provide a corrosion-resistant, low-electrical-resistance connection. The staff confirmed that the applicant's maintenance activities have not revealed significant aging effects or mechanisms associated with switchyard bus and connections to date. Based on its review, the staff determined that loss of material due to wind-induced abrasion and fatigue, increased resistance of connection due to oxidation or loss of preload of switchyard bus and connections are not significant AERMs at Salem.

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 line items that apply to LRA Section 3.6.2.2.3, 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).

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.6.2.3 AMR Results That Are 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 a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects.

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 section.

3.6.2.3.1 Fuse Holders – Metallic Clamp – Summary of Aging Management Evaluation – LRA Table 3.6.2-1

In LRA Table 3.6.2-1 under "fuse holders," the applicant indicated that, based on Salem design and operating experience, aging effects and mechanisms are not applicable for Salem fuse holders. The applicant also stated that the metallic clamp portion of in-scope fuse holders that are not part of a larger assembly are not subject to frequent manipulation or environment conditions that could result in aging effects. The applicant included note I, which states that the aging effects in the GALL Report for this component, material, and environment combination are not applicable. The applicant stated in LRA Section 3.6.2.3 that, at Salem, there are 13 enclosed electrical panels that contain only fuse holders and terminal blocks that are within the scope of license renewal and are not part of a larger assembly. The enclosed electrical panels that contain only fuse holders and terminal blocks are located in the auxiliary building. The applicant stated that these enclosed panels are located in an environment that does not subject them to moisture, chemical contamination, oxidation, and corrosion. The panels are located in various rooms inside the auxiliary building. The environment inside these rooms is a controlled air environment. Therefore, the applicant stated that oxidation and corrosion are not a concern, since these fuse holders are not located in or near a humid area, nor are they exposed to industrial or oceanic environments. The applicant further stated that the fuse panels are not subject to outside weather conditions and are, therefore, not subject to moisture from precipitation. The applicant stated that their indoor location in the auxiliary building means they do not experience high relative humidity during normal conditions. A second barrier that protects these fuse holders from exposure to moisture is their location inside an enclosed electrical panel. The applicant further stated that these fuse holders are protected from chemical contamination by their location and are enclosed within an electrical panel and environmentally controlled inside a building. There are no sources of chemicals in the vicinity of the electrical panels. The applicant also stated that its walkdown of these enclosed electrical panels confirmed that the operating conditions for these holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion.

The applicant stated that fuse holders located in the auxiliary building are for 115-volt AC control power. The loads are instrumentation and control circuits that operate at low currents where no appreciable thermal cycling or ohmic heating occurs. Therefore, the applicant stated that electrical and thermal cycling is not considered an applicable aging mechanism for these fuse holders. The applicant also stated that mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature.

The applicant stated that wear and fatigue is caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventive maintenance. The applicant also stated that these fuse holders are located in an electrical panel that is not mounted on moving or rotating equipment such as compressors, fans, or pumps. Because the electrical panels are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the applicant concluded that the metallic clamps of these fuse holders will not exhibit the aging effect of fatigue due to mechanical stresses and/or frequent manipulation.

During the audit of the LRA from February 16–19, 2010, the staff conducted a walkdown to these fuse holder panels and discussed these fuse holders with the applicant technical staff. The staff confirmed that these fuse holders are installed in indoor air-controlled environments. The staff determined that the aging effects and mechanisms as identified in the GALL Report, Volume 2, Revision 1, item VI.A-8 are not applicable to the fuse holders at Salem. Mechanical stress resulting from electrical faults and transients is not considered a credible aging mechanism since they are infrequent and random in nature. Furthermore, stresses resulting from electrical faults are mitigated by fast acting circuit protective devices (e.g., circuit breakers, fuse elements). The fuses are not routinely removed and reinserted to the metallic clamps. The fuses are only removed during fuse replacement with circuit isolation performed by circuit breakers in the circuit. Therefore, fatigue is not an applicable aging effect. The fuse panels are mounted on the wall and not on rotating machinery or in close proximity to a rotating machine. Therefore, vibration is not an applicable aging effect. The fuse holders are located in a controlled air environment and are not exposed to fluid system leakage. Therefore, chemical contamination and corrosion is not an aging effect. These fuses are used in low-voltage/low-current application such that there is no significant ohmic heating. Ohmic heating/thermal cycling is not an applicable aging effect. The auxiliary room is an HVAC controlled air environment and oxidation of copper alloy is not expected in this environment. The staff conducted a walkdown of the enclosed electrical panels and confirmed that the operating conditions for these holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, the staff determined that the aging effects and mechanisms identified in the GALL Report are not applicable to Salem.

In LRA Table 3.6.2-1, under item 3.6.1-11, the applicant stated that for cement and metal material inside high-voltage insulators exposed to an air-outdoor environment, there is no aging effect and no AMP is proposed. The AMR items cite generic note I and note 3 in LRA Table 3.6.2-1, which states that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. Based on Salem design and operating experience, loss of material is not applicable for the high-voltage insulators. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination. The cement is used as filler for mechanically jointing the porcelain with the caps and pins and is a high quality Portland cement. The cement is not subject to any aging because it is inside high-voltage insulators. Loss of material due to corrosion of the metal cap and pin is not a significant aging effect that can cause a loss of intended function for insulation because the metal pin and cap are constructed of various galvanized metals. Furthermore, the SRP-LR does not address any aging for cement and metal material of high-voltage insulators and only addresses the surface contamination and loss of material due wind-induced mechanical wear.

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 addressed in the GALL Report. The staff finds 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).

3.6.3 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 Appendix B, “Aging Management Programs.” 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 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 applicable UFSAR supplement program summaries and concludes that the UFSAR 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 the activities authorized by the renewed license will continue to be conducted 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 NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section of the safety evaluation report (SER) addresses the identification of time-limited aging analyses (TLAAs). In Sections 4.2 through 4.7 of the license renewal application (LRA), PSEG Nuclear, LLC (PSEG or the applicant) addressed the TLAAs for Salem Nuclear Generating Station (Salem) Units 1 and 2. SER Sections 4.2 through 4.7 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. Pursuant to Title 10, Section 54.21(c)(1), of the Code *of Federal Regulations* (10 CFR 54.21(c)(1)), applicants must list TLAAs as defined in 10 CFR 54.3, "Definitions."

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list existing plant-specific exemptions granted in accordance with 10 CFR 50.12, "Specific Exemptions," based on TLAAs. For any such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for Salem Units 1 and 2 against the six criteria specified in 10 CFR 54.3. The applicant indicated that it had identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), engineering calculations, technical reports, engineering work requests, licensing correspondence, and applicable vendor reports. In LRA Table 4.1-1, "Time Limited Aging Analysis Applicable to Salem," the applicant listed the following applicable TLAAs:

- reactor vessel neutron embrittlement
- metal fatigue of piping and components
- other plant-specific analyses
- fuel transfer tube bellows design cycles
- crane load cycle limits
- environmental qualification of electrical equipment

As required by 10 CFR 54.21(c)(2), the applicant must list all exemptions granted pursuant to 10 CFR 50.12, based on TLAAs, as defined in 10 CFR 54.3, and evaluated and justified for continuation through the period of extended operation.

The applicant stated that its search identified one exemption granted pursuant to 10 CFR 50.12 that remains in effect through the period of extended operation that is based upon a TLAA. The applicant further stated that this is an exemption from the requirement of 10 CFR Part 50,

Appendix A, General Design Criterion 4 to assume a break equivalent to the double-ended rupture of the largest pipe in the reactor coolant system (RCS). The applicant stated that the supporting leak-before-break (LBB) analysis is based, in part, upon an evaluation of fatigue effects for the original 40-year licensed operating period and that this TLAA is described in Section 4.4.3. The applicant further stated that this TLAA was evaluated for 60 years and provides justification for continuation of this exemption for the period of extended operation.

4.1.2 Staff Evaluation

LRA Section 4.1.1 documents the applicant's methodology for identifying applicable TLAAs, and LRA Table 4.1-1 provides a list of the TLAAs that are applicable. The staff reviewed the information to determine whether the applicant had provided sufficient information pursuant to 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As defined in 10 CFR 54.3, TLAAs meet the following six criteria:

(1) involve systems, structures, and components within the period of extended operation, pursuant to 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) are determined to be relevant by the applicant in making a safety determination

(5) involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, pursuant to 10 CFR 54.4(b)

(6) are contained or incorporated by reference in the CLB

The staff noted that the applicant's list of potential TLAAs was assembled using the following regulatory and industry documents and experience:

- NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR)
- NUREG-1801, "Generic Aging Lessons Learned (GALL) Report"
- Nuclear Energy Institute (NEI) 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR 54—The License Renewal Rule"
- 10 CFR Part 54 Final Rule "Statement of Considerations"
- Past LRAs

The staff finds the applicant's use of these documents to compile a list of potential TLAAs reasonable because the applicant has used all available resources from the staff, NEI, and past LRAs.

Using the documents listed above, the applicant performed a review of its CLB in order to determine if the design or analysis feature of each potential TLAA, in fact, exists at Salem; to ascertain if the feature is in its licensing basis; and to identify additional potential plant-specific TLAAs. In accordance with 10 CFR 54.21(c), the potential TLAAs that meet all six criteria of a TLAA as defined in 10 CFR 54.3(a), are actual TLAAs and require a disposition. The applicant reviewed the six criteria based on information in the CLB source documents (as listed above) and from other source documents for the potential TLAAs such as:

- design-basis documents
- specifications
- calculations
- environmental qualification binders

The staff finds the applicant's approach in determining TLAAs reasonable because the applicant has performed a comprehensive search through its CLB, based on available staff and industry guidance and experience, and has reviewed the potential TLAAs against the six criteria of a TLAA as defined in 10 CFR 54.3(a).

The staff confirmed that the applicant's LRA includes the TLAAs that are normally applicable to pressurized water reactor (PWR) applications, including:

- TLAAs on reactor vessel neutron embrittlement
- TLAAs on metal fatigue of piping and components
- TLAAs on fuel transfer tube bellows design cycles
- TLAAs on environmental qualification of electrical equipment

The staff finds the applicant's identification of these TLAAs acceptable because they are consistent with the TLAAs identified in SRP-LR Sections 4.2, 4.3, 4.4, and 4.6 as being applicable to PWR LRAs.

The staff also verified that the LRA included the following additional plant-specific TLAAs:

- reactor vessel underclad cracking analyses

- reactor coolant pump flywheel fatigue crack growth analyses

- leak-before-break analyses

- applicability of American Society of Mechanical Engineers (ASME) Code Case N-481 to the Salem Units 1 and 2 reactor coolant pump casings

- Salem Unit 1 volume control tank flaw growth analysis

The staff confirmed that the applicant's identification of these additional TLAAs satisfies the recommendation in SRP-LR Section 4.7 which states that the applicant identify any additional analyses for the facilities that meet the definition of a TLAA, in accordance with the requirements of 10 CFR 54.3. The staff did not identify any omissions of TLAAs for this LRA.

Based on its review, the staff concludes that the applicant has satisfied the requirements of 10 CFR 54.3 to identify the TLAAs that are applicable to the LRA because the applicant has satisfied the TLAA identification guidance and recommendations in SRP-LR Sections 4.2, 4.3, 4.4, 4.5, 4.6, and 4.7.

The staff confirmed that the TLAAs identified by the applicant as being applicable to the LRA have been evaluated by the applicant against the provisions and criteria of 10 CFR 54.21(c)(1). The staff's evaluations of these TLAAs are provided in SER Sections 4.2, 4.3, 4.4, 4.5, 4.6, and 4.7.

As required by 10 CFR 54.21(c)(2), the applicant must list all exemptions granted in accordance with 10 CFR 50.12, based on TLAAs, and evaluate and justify continuation through 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 concludes, in accordance with 10 CFR 54.21(c)(2), that there is one TLAA-based exemption that the applicant must justify prior to entering into and continuing through the period of extended operation. The staff noted LRA Section 4.4.3 describes this exemption and the staff's evaluation is documented in SER Section 4.4.3.2.

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff confirms, as required by 10 CFR 54.21(c)(2), that one exemption to 10 CFR 50.12 had been granted based on a TLAA.

4.2 Reactor Vessel Neutron Embrittlement

Neutron embrittlement is the term for changes in mechanical properties of reactor pressure vessel (RPV) materials caused by exposure to fast neutron flux (E > 1.0 MeV) within the vicinity of the reactor core, called the beltline region. The most pronounced material change is a reduction in fracture toughness. As fracture toughness decreases with cumulative fast neutron exposure, the material's resistance to cleavage and ductile fracture decreases. Fracture toughness also depends on temperature. The reference temperature nil-ductility transition (RT_{NDT}), above which the material behaves in a ductile manner, and below which the material behaves in a brittle manner, increases as fluence increases and requires higher temperatures for continued ductility. Section 50.60 of 10 CFR Part 50 requires all light-water reactors to meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant pressure boundary (RCPB) in Appendices G and H of 10 CFR Part 50. The RT_{NDT} value which is evaluated at one-quarter or three-quarters of the RPV wall thickness (¼ T or ¾ T) for a specified fluence, as characterized in effective full-power year (EFPY), is usually referred to as adjusted reference temperature (ART) in the P-T limit applications. Section 50.61 of 10 CFR Part 50 provides the fracture toughness requirements protecting the RPV of a PWR against the consequences due to a pressurized thermal shock (PTS) event: a severe overcooling, concurrent with or followed by significant pressure in the RPV. Neutron fluence, reactor vessel material upper-shelf energy (USE), PTS, and P-T limits are time-dependent items that must be investigated to evaluate RPV embrittlement or reduction of fracture toughness. The CLB analyses evaluating reduction of fracture toughness of the RPV for the period of extended operation are TLAAs. The following sections address neutron fluence, USE, PTS, and P-T limits for RPV beltline materials for the period of extended operation.

4.2.1 Neutron Fluence Analysis

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 summarizes the evaluation of neutron fluence for the period of extended operation.

PSEG stated that new fluence projections were performed for the extended life operating period assuming an accrual of 50 EFPY of neutron exposure. The applicant stated that 50 EFPY bound the exposure with a 100 percent capacity factor from November 2007 through the end of the period of extended operation with the exception of a 17-day refueling outage interval every other year. Specifically, these assumptions would result in exposures of 47 EFPY at Unit 1 and 48 EFPY at Unit 2.

PSEG stated that the predicted period of extended operation vessel fluence values satisfy the requirements set forth in Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

PSEG provided the fluence projections in LRA Tables 4.2.1-1 and 4.2.1-2 and concluded, pursuant to 10 CFR 54.21(c)(1)(ii), that the fluence analyses have been projected to the end of the period of extended operation.

4.2.1.2 Staff Evaluation

LRA Section 4.2.1 stated that the current RPV embrittlement analyses are based on predicted 40-year end-of-license (EOL) fluence values of 32 EFPY. In a request for additional information (RAI 4.2.1-1), the staff questioned whether the analysis for 32 EFPY are those approved by the NRC on May 25, 2001, regarding a power uprate request, P-T limits revision, and an exemption request to use ASME Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves."

In addition, the staff requested that the applicant provide the basis for reducing the RPV fluence value from 2.42E+19 at 48 EFPY (Westinghouse Commercial Atomic Power Vendor Report (WCAP)-15565, Revision 1) to 1.83E+19 at 50 EFPY (LRA) for Unit 1 and from 2.66E+19 at 48 EFPY (WCAP-15566, Revision 1) to 1.96E+19 at 50 EFPY (LRA) for Unit 2, and provide additional references in LRA Section 4.8 to support the fluence values in LRA Tables 4.2.1-1 (Unit 1) and 4.2.1-2 (Unit 2).

In its response dated April 20, 2010, the applicant confirmed that the CLB P-T limits were approved in the May 25, 2001, safety evaluation (SE). It also provided two additional references to LRA Section 4.8, supporting the fluence values in LRA Tables 4.2.1-1 (Unit 1) and 4.2.1-2 (Unit 2). The response further clarified that four improvements to the fluence analyses (i.e., fluence methodology changes, incorporation of actual power uprate implementation, use of actual fuel cycle analyses, and implementation of low leakage loading patterns) result in the overall neutron fluence reductions noted in the LRA relative to the projections in the CLB documents WCAP-15565, Revision 1 for Unit 1 and WCAP-15566, Revision 1 for Unit 2.

Regarding the adherence of the applicant's fluence calculations to RG 1.190, the staff confirms that the fluence values were calculated in a manner consistent with the methodology described in two NRC-approved licensing topical reports, WCAP-14040-NP-A report, "Methodology Used to Develop Cold Overpressure Mitigating Systems Setpoints and RCS Heatup and Cooldown Limit Curves," and WCAP-16083-NP-A, "Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, May 2006."

The methodology described in both documents is acceptable to the staff for fluence calculations insofar as both documents have been found to describe methods that meet the recommendations of RG 1.190. PSEG's fluence calculations for Units 1 and 2 were performed using the two-dimensional discrete ordinates code (DORT) with the BUGLE-96 cross Section library, which was derived from the Evaluated Nuclear Data File (ENDF/B-VI). Approximations include a P_5 Legendre expansion for anisotropic scattering and an S_{16} order of angular quadrature. These approximations are of a higher order than the P_3 expansion and S_8 quadrature suggested in RG 1.190. Space and energy dependent core power (neutron source) distributions and associated core parameters are treated on a fuel cycle specific basis. Three-dimensional flux solutions are constructed using a synthesis of azimuthal, axial, and radial flux. Source distributions include cycle-dependent fuel assembly initial enrichments, burnups, and axial power distributions, which are used to develop spatial and energy dependent core source distributions that are averaged over each fuel cycle. This method accounts for source energy spectral effects by using an appropriate fission split for uranium and plutonium isotopes based on the initial enrichment and burnup history of each fuel assembly. The neutron transport calculations, as described above, are performed in a manner consistent with the guidance set forth in RG 1.190.

Because the fluence calculation methodology is NRC-approved and adherent to RG 1.190 and the applicant has provided appropriate references, the staff finds that RAI 4.2.1-1 is resolved and the provided calculated fluences in LRA Tables 4.2.1-1 and 4.2.1-2 are acceptable.

4.2.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the neutron fluence analyses for RPV materials in LRA Section A.4.2.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address neutron fluence analyses is adequate.

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that for reactor vessel neutron fluence, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.2.2 Upper-Shelf Energy Analyses

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 summarizes the evaluation of USE values for the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii), having projected the Charpy USE using the 50 EFPY fluences described in LRA Section 4.2.1, as attenuated to ¼ T location in the wall thickness.

Charpy USE for the beltline forgings and welds of Units 1 and 2 were determined using surveillance data (Position 2.2 of RG 1.99, Revision 2), and the Charpy USE for the extended beltline materials was determined without the use of surveillance data (Position 1.2 of the RG). The USE values for the beltline and extended beltline materials are projected to remain above the 50 foot-pound (ft-lb) requirement through the period of extended operation as indicated in LRA Tables 4.2.2-1 and 4.2.2-2 for Salem Units 1 and 2, respectfully.

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 to verify that the Charpy USE analyses have been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii), and consistent with SRP-LR Section 4.2.2.1.1.2.

Appendix G to 10 CFR Part 50 contains screening criteria that establish limits on the USE values for RPV materials after neutron irradiation exposure. The regulation requires the initial USE value be greater than 75 ft-lbs in the unirradiated condition and the value be greater than 50 ft-lbs in the irradiated condition throughout the licensed life of the plant. USE values of less than 50 ft-lbs may be acceptable to the staff if it can be demonstrated that these lower values will provide margins of safety against brittle fracture equivalent to those required by ASME Code Section XI, Appendix G.

According to RG 1.99, Revision 2, the predicted decrease in USE values due to neutron embrittlement during plant operation is dependent upon the amount of copper (Cu) in the material and the predicted neutron fluence for the material. As indicated above in SER Section 4.2.2.1, the applicant stated that it used Position 2.2 to determine the Charpy USE values at the end of the period of extended operation for the RPV beltline forgings and welds because more than two sets of surveillance data are available for each of these materials. This statement is not consistent with information in LRA Table 4.2.2-1 for Unit 1, which shows that surveillance data was used for evaluating only the intermediate shells, and information in LRA Table 4.2.2-2 for Unit 2, which shows that surveillance data was used for evaluating only one intermediate shell. In addition, the NRC's Reactor Vessel Integrity Database (RVID) indicates that Intermediate Shell Axial Weld 2-042 of the Unit 1 RPV has more than one surveillance data point; likewise, WCAP-15692, "Analysis of Capsule Y from the Public Service Electric and Gas Company Salem Unit 2 Reactor Vessel Radiation Surveillance Program," indicates that Intermediate Shell Axial Weld 2-442 of the Unit 2 RPV has more than one surveillance data.

By letter dated, March 22, 2010, the staff issued RAI 4.2.2-1, which requested that the applicant: (1) clarify these inconsistencies and (2) evaluate its USE values for these weld materials having at least two surveillance data.

In its response to part (1) of RAI 4.2.2-1, dated April 20, 2010, the applicant provided revised paragraphs for LRA Section 4.2.2 to remove the inconsistency with LRA Tables 4.2.2-1 and 4.2.2-2 regarding the evaluation of RPV beltline materials using surveillance data. Therefore, RAI 4.2.2-1, part (1) is resolved.

In its response to part (2) of RAI 4.2.2-1, the applicant stated that surveillance data were not used for intermediate shell axial welds because the surveillance weld for each unit was fabricated from only one of the two weld wire heats used for the RPV welds. This justification is acceptable to the staff because surveillance weld using one heat is not representative of the RPV weld using two heats of weld wire.

In addition, to confirm the applicant's analysis, the staff performed a USE evaluation using the surveillance data. In both cases, the staff confirms that the measured USE from the surveillance data meets or exceeds that provided by the applicant, confirming the validity of the applicant's evaluation, therefore, RAI 4.2.2-1, part (2) is resolved.

For other RPV beltline materials, the staff performed its evaluation using the NRC's RVID. The staff found that the Cu contents and unirradiated USEs for Salem Units 1 and 2 RPV beltline materials in LRA Tables 4.2.2-1 and 4.2.2-2 are almost identical to those in the RVID, except for the Cu contents of two welds: the lower shell longitudinal welds for Unit 1, and the intermediate shell longitudinal welds for Unit 2. In both cases, the discrepancies are less than 5 percent and have caused no impact on the subject welds' USE evaluations. The staff confirmed the applicant's projected USE values at the end of the period of extended operation for beltline and extended beltline materials for Units 1 and 2. However, because RVID does not contain information for the extended beltline materials for Units 1 and 2, the staff issued by letter dated March 22, 2010, RAI 4.2.2-2, which requested that the applicant describe the procedures used to determine the chemistry data, initial RT_{NDT}, margins, and initial USE values for the extended beltline materials to demonstrate that it has applied consistent approaches for both the beltline and the extended beltline materials.

In its response dated April 20, 2010, the applicant provided additional information supporting the chemistry and initial USE values in LRA Tables 4.2.2-1 and 4.2.2-2 for USE predictions and initial RT_{NDT} values in LRA Tables 4.2.3-1 and 4.2.3-2 for PTS predictions for the extended beltline materials. The applicant also stated in its response that the material data for the extended beltline materials are from the same sources as those used for the beltline materials: the Certified Material Test Reports (CMTRs); Combustion Engineering (CE) Report CE NPSD-1119, "Updated Analysis for Combustion Engineering Fabricated Reactor Vessel Welds Best Estimate Copper and Nickel Content"; the PTS rule (10 CFR 50.61); and CE Report CEN-622-A, "Generic Upper Shelf Values for Linde 1092, 124, and 0091 Reactor Vessel Welds." The CE NPSD-1119 report has been reviewed by the staff in support of the effort related to Generic Letter (GL) 92-01, Revision 1, "Reactor Vessel Structural Integrity," for CE plants. The best estimate method used to determine the chemistry data for the RPV beltline materials is consistent with the staff's established position in reviewing GL 92-01, Revision 1 submittals. Therefore, consistent NRC-accepted approaches have been used to determine the material information for both beltline and extended beltline materials and RAI 4.2.2-2 is resolved.

The staff used Position 1.2 of RG 1.99, Revision 2 and confirms that the projected USE value is 53 ft-lbs for the limiting material (upper shell plate B2401-3) of Unit 1, and 60 ft-lbs for the limiting material (intermediate shell longitudinal welds 2-442 B and C) of Unit 2. The limiting USE material identified in the RVID for Unit 1 is no longer limiting because an extended beltline material in the LRA now becomes the limiting material. The applicant's USE values are consistent with those in the CLB based on the WCAP-15566, Revision 1, "Salem Unit 2 Heatup and Cooldown Curves for Normal Operation."

Therefore, pursuant to 10 CFR 54.21(c)(1)(ii), the Salem Units 1 and 2 RPV beltline and extended beltline materials, which have 50 EFPY USE values at ¼ T greater than 50 ft-lbs, meet the 10 CFR Part 50, Appendix G USE requirement to the end of the period of extended operation and, therefore, are acceptable.

4.2.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the USE values for RPV materials in LRA Section A.4.2.2. On the basis of its review of the UFSAR supplement and consistent with SRP-LR Section 4.2.3.1.1.2, the staff concludes that the summary description of the applicant's actions to address USE is adequate.

4.2.2.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.2.3.1.1.2, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE analyses have been projected to the end of the period of extended operation and will meet the criteria defined in Appendix G to 10 CFR Part 50. 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), and, therefore, is acceptable.

4.2.3 Pressurized Thermal Shock Analyses

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 summarizes the PTS evaluation of Units 1 and 2 beltline and extended beltline materials for the period of extended operation against the screening criteria established in accordance with the PTS rule 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii).

For Unit 1, the limiting reference temperature for PTS (RT_{PTS}) for axial welds and plates is 125 °C (258 °F) for the lower shell longitudinal weld 3-042C, and the limiting RT_{PTS} value for the circumferentially oriented welds is 109 °C (229 °F) for the intermediate-to-lower shell circumferential weld 9-042. For Unit 2, the limiting RT_{PTS} value for axial welds and plates is 115 °C (239 °F) for the lower shell longitudinal welds 3-442 A and C, and the limiting RT_{PTS} value for the circumferential welds is 48 °C (118 °F) for the intermediate shell-to-lower shell circumferential weld 9-442.

The applicant concluded that each RPV material for Units 1 and 2 that has a surface fluence value exceeding 1.0 x 10^{17} neutrons per square centimeter (n/cm^2) (E > 1.0 MeV) at 50 EFPY has been demonstrated to have an RT_{PTS} value less than the applicable screening criterion and, therefore, the RT_{PTS} analyses have been satisfactorily projected for the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.3 to verify that the PTS analyses have been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii), and consistent with SRP-LR Section 4.2.2.1.2.2.

Per the requirements of 10 CFR 50.61, licensees must demonstrate that the RT_{PTS} values for each RPV beltline material have been projected through the end of their operating license. The RT_{PTS} value for each beltline material is evaluated from:

$$RT_{PTS} = RT_{NDT(u)} + \Delta RT_{PTS} + M$$

Where:

- $RT_{NDT(u)}$ is the unirradiated RT_{NDT}
- ΔRT_{PTS} is the shift in RT_{PTS} caused by neutron irradiation
- M is the margin term to account for uncertainties

The methodology used for determining ΔRT_{PTS} and the margin term M are described in the PTS rule, including provisions for use of surveillance data. The PTS rule also provides screening criteria of 132 °C (270 °F) for plates, forging, and axial weld materials and 149 °C (300 °F) for circumferential weld materials.

In LRA Tables 4.2.3-1 and 4.2.3-2, the applicant presented the RT_{PTS} values for 50 EFPY for Units 1 and 2. Also presented in these tables were the input parameters necessary for calculating the RT_{PTS} values. The RVID indicates that the two surveillance weld data for Unit 1 is representative of its intermediate shell axial weld 2-042 which, according to WCAP-15565, Revision 1, gives a chemistry factor of 192.5 °F. Since this value is lower than 103 °C (217.2 °F) based on Position 1.1 for this weld (LRA Table 4.2.3-1), the staff finds that the applicant's approach provides a conservative result and, therefore, is acceptable.

During its review, the staff identified discrepancies between data in LRA Tables 4.2.3-1 and 4.2.3-2 and that in the RVID. In addition, the LRA information differs from that in other license documents. Specifically, the chemistry factors for intermediate shell plates, B2402-1, B2402-2, and B2402-3, and the lower shell longitudinal weld 3-042C (the limiting beltline material of Salem Unit 1) for Salem Unit 1 differs from those in the RVID. For Salem Unit 2, LRA Table 4.2.3-2 shows a chemistry factor of 87.3 °C (189.1 °F) based on the table of the PTS rule for intermediate shell longitudinal weld 2-442. However, WCAP-15692 shows a value of 90.29 °C (194.53 °F) based on surveillance data for this weld. By letter dated March 22, 2010, the staff issued RAI 4.2.3-1 requesting the applicant was asked to provide a basis and justification for the information provided in the LRA.

In its response dated April 20, 2010, the applicant stated that the update of the chemistry factors for intermediate shell plates B2402-1, B2402-2, and B2402-3 Unit 1 is based on a revised evaluation of the chemistry factors which result from the use of updated surveillance capsule fluence values. The staff finds this acceptable because specimen fluence values reported in prior surveillance capsule reports are frequently updated in later surveillance capsule reports based on information from additional surveillance data. The staff confirms that the resulting RT_{PTS} values based on the chemistry factor changes for these plates are still well below the 132 °C (270 °F) criterion. The applicant also revised the chemistry data, the USE values, and the RT_{PTS} values for the two groups of the lower shell longitudinal weld 3-042 (one group is the limiting RPV material). The staff confirms that the revised USE values remain unchanged and the revised RT_{PTS} values, though modestly higher, are still below the 132 °C (270 °F) criterion. For intermediate shell longitudinal weld 2-042, for which the surveillance data may be applicable, the staff confirms that the applicant's approach of using the PTS rule chemistry tables gives a higher, and thus conservative, chemistry factor for this weld.

In its response dated April 20, 2010, the applicant stated that the surveillance data is not used for the Salem Unit 2 intermediate shell axial weld because the surveillance weld was fabricated using only one of the Salem RPV weld wire heats and is not representative of intermediate shell longitudinal welds 2-442 A, B, and C. This justification is acceptable to the staff because the surveillance weld is not representative of the intermediate shell longitudinal weld 2-442A, B, and C. To confirm acceptability of the applicant's analysis, the staff performed a PTS evaluation for this weld using the higher chemistry factor based on the surveillance data and the reduced margin associated with this approach and found that the applicant's RT_{PTS} values are conservative. Hence, RAI 4.2.3-1 is resolved. In summary, the staff confirms the applicant's revised RT_{PTS} value of 130.5 °C (267 °F) (based on a revised LRA Table 4.2.3-1 from the applicant's response dated April 20, 2010) for the limiting material for Unit 1 (lower shell longitudinal weld 3-042 C) and RT_{PTS} value of 115 °C (239 °F) for the limiting material for Unit 2 (lower shell longitudinal welds 3-442 A and C).

Based on the above discussion, the staff concludes that all Salem Units 1 and 2 RPV beltline and extended beltline materials satisfy the PTS requirements of 10 CFR 50.61 through the period of extended operation. The applicant's TLAA is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that Units 1 and 2 RPV materials will have adequate RT_{PTS} values and fracture toughness through the period of extended operation.

4.2.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of PTS in LRA Section A.4.2.3. On the basis of its review of the UFSAR supplement and consistent with

SRP-LR Section 4.2.3.1.2.2, the staff concludes that the summary description of the applicant's actions to address PTS is adequate.

4.2.3.4 Conclusion

On the basis of its review and consistent with SRP-LR Section 4.2.3.1.2.2, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the PTS analyses have been projected to the end of the period of extended operation and will continue to meet the requirements of the PTS rule (10 CFR 50.61). 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), and, therefore, is acceptable.

4.2.4 Reactor Vessel Pressure-Temperature Limits, Including Low Temperature Overpressurization Protection Limits

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the evaluation of P-T limits for the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant developed the ART values based on the material properties in LRA Tables 4.2.3-1 and 4.2.3-2 and the ¼ and ¾ RPV wall thickness (¼T and ¾ T) fluences for 50 EFPY. The resulting ARTs for the limiting materials of Units 1 and 2 are summarized in LRA Tables 4.2.4-1 and 4.2.4-2 and were used to develop the P-T limits in accordance with the requirements of 10 CFR Part 50, Appendix G and ASME Code Section XI, Appendix G. Specifically, Salem P-T limit curves for normal heatup and cooldown were developed using the 1998 Edition through the 2000 Summer Addenda of the ASME Code Section XI, Appendix G methodology and ASME Code Case N-641, "Alternative Pressure-Temperature Relationship and Low Temperature Overpressure Protection System Requirements." The current Salem P-T curves are applicable to 32 EFPY.

The P-T limit and low temperature overpressure protection (LTOP) analyses have been projected to the end of the period of extended operation; however, they have not been submitted with the LRA. The Reactor Vessel Surveillance Program monitors RPV embrittlement and provides data that are used to update the P-T limits. PSEG will submit updates to the P-T and LTOP limits for Units 1 and 2, for staff approval as necessary to maintain compliance with 10 CFR Part 50, Appendix G.

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify that the effects of aging on the intended function will be adequately managed by the applicant for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii), and consistent with SRP-LR Section 4.2.2.1.3.3.

As confirmed by the applicant's response to RAI 4.2.1-1, the CLB P-T limits for 32 EFPY were approved by the staff on May 25, 2001. The staff finds that the limiting 50 EFPY ARTs in LRA Tables 4.2.4-1 and 4.2.4-2 result from two major changes: the 50 EFPY fluence values and the chemistry data for the limiting material of Salem Unit 1. The former was accepted by the staff (SER Section 4.2.1.2), and the latter was questioned and accepted in RAI 4.2.3-1. The chemistry factor change resulted in an increase of 8 °F for the Unit 1 limiting ART at ¼ T for

50 EFPY. LRA Section 4.2.4 states that updated P-T limits for the period of extended operation have been projected to the end of the period of extended operation. However, the applicant did not include the updated P-T limits in the LRA.

The staff does not require the updated P-T limit curves for the period of extended operation to be submitted as part of the applicant's LRA for this TLAA. However, the applicant is required to submit revised P-T limits in accordance with 10 CFR Part 50, Appendix G prior to the expiration of the facility's current P-T limit curves, considering the increase of Unit 1 limiting ART and plant-specific embrittlement information from additional surveillance data provided by the Reactor Vessel Surveillance Program. Hence, the staff finds that the applicant's plan to manage the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii) is acceptable because revised P-T limit curves, meeting the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G, will be implemented by the license amendment process (i.e., through revision of the plant technical specifications (TSs)).

4.2.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of P-T limits in LRA Section A.4.2.4. On the basis of its review of the UFSAR supplement consistent with SRP-LR Section 4.2.3.1.3.3, the staff concludes that the summary description of the applicant's actions to address P-T limits is adequate.

4.2.4.4 Conclusion

On the basis of its review consistent with SRP-LR Section 4.2.3.1.3.3, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that for P-T limits, the effects of aging on the intended function will be adequately managed by the applicant 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), and, therefore, is acceptable.

4.3 Metal Fatigue of Piping and Components

A metal component that is subjected to cyclic loads may fail at load levels lower than its design load carrying capacity due to a well-known phenomenon known as fatigue. Fatigue involves crack initiation and propagation. The fatigue life of a structural component depends on the material used for the structure, the environment to which the structural component is exposed, and the number of occurrences or repetitions of cyclic loads and the magnitude of the applied fluctuating loads.

LRA Section 4.3 states that metal fatigue was evaluated in the design process for pressure boundary components, including the reactor vessel, reactor coolant pumps (RCPs), SGs, pressurizer, piping, valves, and components of primary, secondary, auxiliary, steam, and other systems. Furthermore, the applicant stated that fatigue TLAAs for pressure boundary components are characterized by determining the applicable design codes and specifications that specify the fatigue design requirements.

Fatigue is age-related degradation caused by cyclic stressing of a component by either mechanical or thermal stresses. Fatigue analyses are TLAAs if they meet the six defined elements pursuant to 10 CFR 54.3(a). If the analyses are based on a number of cycles estimated for the current license term, they may meet the 10 CFR 54.3(a)(3) criterion of “defined by the current operating term.” The applicant evaluated the TLAAs in accordance with 10 CFR 54.21(c)(1).

4.3.1 Nuclear Steam Supply System Pressure Vessel and Component Fatigue Analyses

4.3.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1 summarizes the evaluation of the pressure vessel components for the period of extended operation. This TLAA is based on the analysis in UFSAR Section 5.2. The applicant stated that metal fatigue evaluation was performed for the nuclear steam supply system (NSSS) pressure vessel and its components that included reactor vessel, reactor vessel closure head, pressurizer, SGs, and RCP casings. The applicant also stated that these components were designed in accordance with ASME Boiler and Pressure Vessel (B&PV) Code Section III for Class A or Class 1 and, therefore, were subject to fatigue analyses. The applicant further stated that these analyses were based upon the number and the amplitudes of design basis transients described in the design specifications and summarized in LRA Table 4.3.1-2, “Design Transient Cycles for NSSS Class A and Class 1 Components at Salem Units 1 and 2.” The applicant reviewed fatigue monitoring data to determine the number of cumulative cycles of each transient that occurred during plant operation. Based on this data, the applicant derived the 60-year projected number of cycles and compared these values to the design basis number of cycles. The applicant concluded that the 60-year projected number of cycles remained bounded by the design-basis number of cycles and that the design-basis fatigue analyses will remain valid for the 60 years of operation. In this TLAA, the applicant dispositioned the TLAA pressure vessel and component fatigue analyses based on the criterion in 10 CFR 54.21(c)(1)(i).

4.3.1.2 Staff Evaluation

The staff reviewed the TLAAs in LRA Section 4.3.1 for NSSS pressure vessel and components against the acceptance criteria in SRP-LR Section 4.3.2.1.1.1 and review procedures in SRP-LR Section 4.3.3.1.1.1 in order to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the NSSS pressure vessel and its components fatigue analyses remain valid for the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- TS 5.7, "Component Cyclic or Transient Limit"
- UFSAR Section 5.2, "Integrity of Reactor Coolant Pressure Boundary"
- UFSAR Table 5.2-10, "Design Thermal and Loading Cycles – AREVA NP Model 61/19T SG – Unit 2"
- UFSAR Table 5.2-10a, "Design Thermal and Loading Cycles – Model F SG – Unit 1"
- 10 CFR 50.55a, "Codes and Standards"

The staff reviewed the applicant's cycle projection methodology in LRA Section 4.3.1 and the actual 60-year transient projection data in LRA Tables 4.3.1-3 and 4.3.1-4 against the design basis limits in LRA Table 4.3.1-2 to determine whether the applicant provided an acceptable basis to disposition the TLAAs in accordance with 10 CFR 54.21(c)(1)(i).

During its review, the staff noted that the applicant is using a linear basis to project the cumulative cycles for the design basis transients to the end of the period of extended operation. The staff noted the applicant's projection methodology is based on 28.5 years of operation for Unit 1 and 25.6 years of operation for Unit 2. The staff confirmed that the applicant derived an average rate of past transient occurrences using 28.5 and 25.6 years of operation for Units 1 and 2. The staff determined that the applicant derived the 60-year cycle projections by adding the cumulative number of occurrences as of December 31, 2007, to the number of cycles predicted to occur in the 31.5 and 34.4 years of future operation for Units 1 and 2, respectively. The staff concluded that this projection methodology is based on the assumption that all monitored transients would not exhibit increasing trends. During its audit and based on the additional information provided by the applicant as referenced in the audit report, the staff confirms that none of the transients listed in LRA Table 4.3.1-2 exhibited increasing trends over the period of operation for which they were assessed (i.e., operations through December 31, 2007). The staff notes that this supports the applicant's conclusion that the linear extrapolation basis is conservative because the linear averaging used in the projection basis is bounding for the actual decreasing trend in transient cycle occurrences over time.

However, the staff also noted that the applicant's 60-year transient occurrence projection basis did not indicate whether there were any gaps in the counting of the design basis transients since the initial startup of the Salem units. By letter dated June 14, 2010, the staff issued RAI 4.3-01 requesting that the applicant clarify whether the cycle counting for the design basis transients at Units 1 and 2 has been performed during the entire period of past operation.

In its response dated July 13, 2010, the applicant stated that it conducted a review of past plant documents to establish cycle counts, which included licensee event reports, monthly operating reports, and the plant's computer-based data archive system. The applicant stated that this review confirmed there were no unmonitored periods during the entire period of past operation. The applicant stated that the review included the entire time of operation except during periods of hot shutdown or cold shutdown conditions. The applicant stated that for each of the design basis transients listed in LRA Tables 4.3.1-3 and 4.3.1-4, the applicant used the larger of the two values for current cycles that either came from the 2007 annual cyclic data report or the review of plant historical information.

Based on its review, the staff finds the applicant's response to RAI 4.3-01 acceptable because the applicant has performed cycle counting during the entire period of past operation, and the applicant has performed a review of plant records to identify any uncounted transients. Further, the applicant has used the highest cycle count resulting from either of the two processes in its evaluation cycles. The staff's concern described in RAI 4.3-01 is resolved.

The staff notes that LRA Section 4.3.1 does not reference the design-basis documents used to confirm the design basis transient limits provided in LRA Table 4.3.1-2. By letter dated June 14, 2010, the staff issued RAI 4.3-02 requesting that the applicant clarify which CLB documents or design-basis documents were used to determine the design basis transient limits for those listed in LRA Table 4.3.1-2, "Design Transient Cycles for NSSS Class A and Class 1 Components at Salem Units 1 and 2."

In its response dated July 13, 2010, the applicant provided a table that lists the CLB or design-basis documents referenced for each of the transients listed in LRA Table 4.3.1-2. The list of references includes:

- Units 1 and 2 TSs, Table 5.7-1, "Component Cyclic or Transient Limits"
- UFSAR Table 5.2-10a, "Design Thermal and Loading Cycles*, Model F SG – Unit 1," Revision 24
- UFSAR Table 5.2-10, "Design Thermal and Loading Cycles*, AREVA NP Model 61/19T SG – Unit 2," Revision 24
- WCAP-12914, "Structural Evaluation of Salem Nuclear Plant Units 1 and 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification," Revision 1
- PSEG Calculations 3SC-013, "Salem Unit 1 & 2 – NRC Bulletin 88-08 Evaluation of Aux. Spray Line," Revision 0
- Safety Evaluation SGS/M-SE-006, "Safety Injection Transients, 1 and ½ Inch Injection Nozzles – Reactor Coolant System, No. 1 Unit," Revision 0, February 9, 1977

The staff reviewed these documents and concluded that they do provide design basis transient limiting values provided in LRA Table 4.3.1-2. The staff's concern described in RAI 4.3-02 is resolved.

Therefore, based on this review, the staff concludes that the applicant's 60-year transient projection basis is acceptable because the linear extrapolation methodology is conservative relative to the actual decreasing trend in transient occurrences from recent plant operations.

The staff reviewed the 60-year cycle projections for the transients in LRA Tables 4.3.1-3 and 4.3.1-4 against the design basis limit values listed for the transients in LRA Table 4.3.1-2. The staff confirmed that the 60-year projected cycles were based on the projection methodology as described above and that for these transients, the 60-year projected number of cycles listed in LRA Tables 4.3.1-3 and 4.3.1-4 are bounded by the design basis limit values listed for the transients in LRA Table 4.3.1-2. Therefore, the staff finds that the applicant has provided a valid basis for dispositioning the TLAAs in accordance with 10 CFR 54.21(c)(1)(i) because the applicant's 60-year linear extrapolation methodology bounds the actual trend in transient occurrences and the 60-year projections results listed for the transients in LRA Tables 4.3.1-3, 4.3.1-4, 4.3.2-1, 4.3.2-2, 4.3.6-1, and 4.3.6-2 are bounded by the design basis limit values listed for these transients in LRA Table 4.3.1-2.

4.3.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of NSSS pressure vessel components fatigue analyses in LRA Section A.4.3.1. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's actions to address NSSS pressure vessel components fatigue analyses is adequate.

4.3.1.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.1.1.1, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that for the metal fatigue TLAA, the analyses for the NSSS pressure vessel and components 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 for the NSSS pressure vessel and its components, as required pursuant to 10 CFR 54.21(d).

4.3.2 Pressurizer Safety Valve and Pilot-Operated Relief Valve Fatigue Analyses

4.3.2.1 Pressurizer Safety Valve

4.3.2.1.1 Summary of Technical Information in the Application

LRA Section 4.3.2 summarizes the evaluation of pressurizer safety valves for the period of extended operation. In this TLAA, the applicant stated that the fatigue analyses for pressurizer safety valves are a TLAA that require evaluation for the period of extended operation. The applicant also stated that for the design basis analyses, the pressurizer safety valves are based on a total of 50 design cycles. The applicant derived the 60-year projected number of cycles used in fatigue analyses of the pressurizer safety valves based on fatigue monitoring data recorded during plant operation. The applicant concluded that the total number of cycles projected for 60 years for the transients of concern (loss of load, feedwater line break, RCP locked rotor, and control rod ejection) remained bounded by the design basis number of cycles, and thus the design basis fatigue analyses will remain valid for the period of extended operation.

In this TLAA, the applicant dispositioned the TLAA for fatigue of pressurizer safety valve fatigue analyses based on the criterion in 10 CFR 54.21(c)(1)(i).

4.3.2.1.2 Staff Evaluation

The staff reviewed the TLAAs in LRA Section 4.3.2.1 for fatigue of the pressurizer safety valves against the acceptance criteria in SRP-LR Section 4.3.2.1.3 and the review procedures in SRP-LR Section 4.3.3.1.3 in order to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the pressurizer safety valves fatigue analyses remain valid for the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- TS 5.7, "Component Cyclic or Transient Limit"
- UFSAR Section 5.5, "Components and Subsystem Design"
- UFSAR Table 5.2-10, "Design Thermal and Loading Cycles – AREVA NP Model 61/19T SG – Unit 2"
- UFSAR Table 5.2-10a, "Design Thermal and Loading Cycles – Model F SG – Unit 1"
- 10 CFR 50.55a, "Codes and Standards"

The staff notes that the applicant's metal fatigue analysis assessment for the pressurizer safety valves is based on a design specification that limits the total number of transient occurrences (for all transients applicable to the valves) to a value of 50. The staff also notes that the applicant identified that the following design basis transients are applicable to the applicant's TLAA for the pressurizer pilot-operated relief valves (PORVs): (1) "Loss of Load," (3) "Feedwater Line Break," (3) "RCP Locked Rotor" and (4) "Control Rod Ejection."

The staff notes that LRA Table 4.3.2-1 lists the current total number of occurrences to date and the 60-year projection results for the applicable design basis transients. During its review, the staff confirms that the applicant is using a linear basis to determine the 60-year cycle projections, consistent with the projection methodology evaluated and found to be acceptable by the staff in SER Section 4.3.1.

The staff notes that the applicant's evaluation is based on a projection of one occurrence each, of the "Feedwater Line Break," "RCP Locked Rotor," and "Control Rod Ejection" transients during the period of extended operation, even though there have been no occurrences of these transients at the plant during current licensed operations. The staff finds this assumption to be acceptable because the applicant has programs, requirements, or design features to minimize the probability for the occurrence of these transients. The staff confirms that, for the pressurizer safety valves, the total number of transient occurrences projected for 60 years of operation for all applicable transients is 7 and 4 for Salem Units 1 and 2, respectively. The staff notes that this demonstrates the number of transient occurrences remains bounded by the total number of transient occurrences allowed in the design specification for the valves.

The staff held a teleconference with the applicant on August 1, 2010, to discuss the disposition of the TLAAs on the pressurizer safety valves and pressurizer PORVs as discussed in LRA

Sections 4.3.2.1 and 4.3.2.2. The staff noted that the analyses the applicant claimed to be TLAAs for the pressurizer safety valves (LRA Section 4.3.2.1) and pressurizer PORVs (LRA Section 4.3.2.2) appeared to be limited only to the total number of cycles and thus, the analyses for these valve types do not appear to be associated with the evaluation of an aging effect. The staff noted that the applicant would not normally have to identify these analyses as TLAAs because they do not appear to conform to Criterion 2 in 10 CFR 54.3(a) (i.e., consider the effects of aging).

By letter dated August 26, 2010, the applicant stated that, upon further review, it determined there are no TLAAs associated with the pressurizer safety valves and PORVs, since the design analyses associated with these valves do not meet all of the criteria of a TLAA as defined in 10 CFR 54.3(a).

The applicant further stated that as part of the detailed TLAA documentation search, it found Westinghouse design specifications for component cycles associated with the valves; however, these design specifications do not consider the effects of aging of the pressurizer safety valves and PORVs. The staff noted that the second criterion of a TLAA, as defined in 10 CFR 54.3(a), states that a TLAA are those licensee calculations and analyses that consider the effects of aging. Furthermore, the staff noted that, since these analyses did not consider the effects of aging, they would not normally have been considered TLAAs; however, the LRA conservatively identified these analyses as TLAAs, evaluated the projected number of cycles associated with the valves' operations, and dispositioned the TLAAs in accordance with 10 CFR 54.21(c)(1)(i). The applicant amended its LRA such that the applicable sections, LRA Sections 4.3.2 and A.4.3.2, are deleted to remove the analyses associated with the valves as TLAAs.

Based on its review, the staff finds it acceptable that LRA Sections 4.3.2 and A.4.3.2 were deleted and that the fatigue analyses for the pressurizer safety valves are not TLAAs because these analyses did not consider the effects of aging and, therefore, do not meet the definition of a TLAA, as defined in 10 CFR 54.3(a).

4.3.2.1.3 UFSAR Supplement

By letter dated August 26, 2010, the applicant amended its LRA to delete LRA Section A.4.3.2. The staff's review of this amendment is documented in SER Section 4.3.2.1.2.

4.3.2.1.4 Conclusion

On the basis of its review, the staff concludes that the fatigue analyses for the pressurizer safety valves are not TLAAs, as defined in 10 CFR 54.3(a). The staff also concludes that a UFSAR supplement is not required.

4.3.2.2 Pressurizer Pilot-Operated Relief Valve Fatigue Analyses

4.3.2.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2 summarizes the evaluation of pressurizer PORVs for the period of extended operation. In this TLAA, the applicant stated that the fatigue analyses for pressurizer PORVs are a TLAA that requires evaluation for the period of extended operation. The applicant also stated that for pressurizer PORVs, the design basis analyses are based on a total of 20,000 design cycles. Based on fatigue monitoring data recorded during plant operation, the applicant derived the 60-year projected number of cycles used in the fatigue analyses of the pressurizer PORVs.

The applicant concluded that the total number of cycles projected for 60 years of operation remain bounded by the design basis number of cycles and that the design basis fatigue analyses will remain valid for the period of extended operation. The applicant dispositioned the TLAA for fatigue of pressurizer PORVs based on the criterion in 10 CFR 54.21(c)(1)(i).

4.3.2.2.2 Staff Evaluation

The staff reviewed the TLAAs in LRA Section 4.3.2.2 for fatigue of the pressurizer PORVs against the acceptance criteria in SRP-LR Section 4.3.2.1.3 and the review procedures in SRP-LR Section 4.3.3.1.3 in order to confirm, in accordance with 10 CFR 54.21(c)(1)(i), that the pressurizer PORVs fatigue analyses remain valid for the period of extended operation.

The staff also reviewed the same additional documents as described in SER Section 4.3.2.1.2. The staff noted that the applicant's metal fatigue analysis for the pressurizer PORVs is based on a design specification that limits the number of transient cycles to 20,000 occurrences for all transients that are applicable to the valves. The staff also noted that the applicant identified that the following design basis transients are applicable to the applicant's TLAA for the pressurizer PORVs: (1) large step load with steam dump, (2) loss of load, (3) loss of flow, and (4) loss of power.

The staff noted that LRA Table 4.3.2-2 lists the total number of cumulative occurrences for these transients to date and the 60-year projection results for these transients. The staff confirms that these projections are based on the applicant's projection methodology provided in LRA Section 4.3.1. The staff evaluated this projection methodology in SER Section 4.3.1 and determined that the applicant's 60-year design basis transient projection basis and results were acceptable and conservative. The staff confirmed that, for the pressurizer PORVs, the total number of 60-year projected cycles is 91 and 40 for Salem Units 1 and 2, respectively. The staff notes that this projected number of transient occurrences is bounded by the number of transient occurrences allowed in the design specification for the pressurizer PORVs (i.e., less than 20,000).

The staff held a teleconference with the applicant on August 1, 2010, to discuss the disposition of the TLAAs on the pressurizer safety valves and PORVs, as discussed in LRA Sections 4.3.2.1 and 4.3.2.2. The staff noted that the analyses that the applicant claimed to be TLAAs for the pressurizer safety valves (LRA Section 4.3.2.1) and pressurizer PORVs (LRA Section 4.3.2.2) appeared to be limited only to the total number of cycles and thus, the analyses for these valve types do not appear to be associated with the evaluation of an aging effect. The staff noted that the applicant would not normally have to identify these analyses as TLAAs because they do not appear to conform to Criterion 2 in 10 CFR 54.3(a) (i.e., consider the effects of aging).

By letter dated August 26, 2010, the applicant stated that, upon further review, it determined there are no TLAAs associated with the pressurizer safety valves and PORVs, since the design analyses associated with these valves do not meet all of the criteria of a TLAA as defined in 10 CFR 54.3(a).

The staff's review of the August 26, 2010, letter and the deletion of LRA Sections 4.3.2 and A.4.3.2 are documented in SER Section 4.3.2.1.2.

Based on its review, the staff finds it acceptable that LRA Sections 4.3.2 and A.4.3.2 were deleted and that the fatigue analyses for the pressurizer PORVs are not TLAAs because these analyses did not consider the effects of aging and, therefore, do not meet the definition of a TLAA as defined in 10 CFR 54.3(a).

4.3.2.2.3 UFSAR Supplement

By letter dated August 26, 2010, the applicant amended its LRA to delete LRA Section A.4.3.2. The staff's review of this amendment is documented in SER Section 4.3.2.1.2.

4.3.2.2.4 Conclusion

On the basis of its review, the staff concludes that the fatigue analyses for the pressurizer PORVs are not TLAAs, as defined in 10 CFR 54.3(a). The staff also concludes that a UFSAR supplement is not required.

4.3.3 American Standards Association/United States of America Standards B31.1 Piping Fatigue Analyses

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3 summarizes the evaluation of American Standards Association/United States of America Standards (ASA/USAS) B31.1 piping for the period of extended operation. This TLAA is based on the analysis in UFSAR Section 5.2. In this TLAA, the applicant stated that the piping was designed in accordance with ASA/USAS B31.1 piping code and, therefore, fatigue analyses were not required, but cyclic load was considered in a simplified manner in the design process. The applicant determined that the total number of 60-year projected cycles does not exceed 7,000 cycles, which is the minimum number of cycles required that would result in application of an allowable stress reduction factor. Therefore, the applicant concluded that the existing analyses of ASA/USAS B31.1 piping for which the allowable range of secondary stresses depends on the number of assumed thermal cycles, remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.3.3.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.3.3 for fatigue of ASA/USAS B31.1 piping against the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 and the review procedures in SRP-LR Section 4.3.3.1.2.1 in order to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the ASA/USAS B31.1 piping fatigue analyses remain valid for the period of extended operation.

The staff reviewed the applicant's cycle projection methodology in LRA Section 4.3.1 and found the applicant's methodology acceptable. From the information provided in LRA Tables 4.3.1-3 and 4.3.1-4, the staff determined that the total number of projected cycles for the design transients applicable to the ASA/USAS B31.1 piping used 4,936 and 4,264 for Salem Units 1 and 2, respectively, and will not exceed the 7,000-cycle limit. Therefore, the staff concludes that the applicant's design transient cycle projection for the period of extended operation will be less than the limit of 7,000 cycles and thus the analysis remain valid for the period of extended operation.

4.3.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of ASA/USAS B31.1 piping fatigue analyses in LRA Section A.4.3.3. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's metal fatigue TLAA for the ASA/USAS B31.1 piping is adequate.

4.3.3.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.1.2.1, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the metal fatigue analyses for the ASA/USAS B31.1 piping 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 for the ASA/USAS B31.1 piping, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.3.4 Supplementary ASME Code Section III, Class 1 Piping and Component Fatigue Analyses

4.3.4.1 NRC Bulletin 88-08, Thermal Stresses in Piping Connected to Reactor Coolant Systems

4.3.4.1.1 Summary of Technical Information in the Application

LRA Section 4.3.4 summarizes the evaluation of supplementary ASME Code Section III, Class 1 piping and component fatigue analysis for the period of extended operation. This TLAA is based on the analysis in response to NRC Bulletin 88-08. In this TLAA, the applicant stated that Units 1 and 2 piping systems were originally designed in accordance with the ASA/USAS B31.1 piping code, however, a number of updated fatigue analyses have been performed for some piping systems and components to address transients that have been identified based on industry practice that were not originally considered. The applicant further stated that these transients include those associated with potential valve leakage transients identified in GL 88-08 for the auxiliary spray line.

The applicant stated that the staff approved Salem's response to NRC Bulletin 88-08, which included the evaluation of the fatigue analyses of the normal and alternate charging lines and the auxiliary spray lines. The applicant also stated that the analyses were based on the requirements of ASME Code Section III, 1986 Edition, Subsection NB-3653 and the fatigue curves of I-9.2.1 and I-9.2.2 and concluded that the cumulative usage factor (CUF) would remain less than 1.0 for the normal and alternate charging lines.

The applicant also performed a fatigue evaluation of the auxiliary spray line for a life of 40 years. The analysis showed that the inadvertent auxiliary spray transient controlled the calculated fatigue usage. The resulting fatigue usage was calculated to be less than 1.0 for 40 years.

In this TLAA, the applicant dispositioned the TLAA for the auxiliary spray lines in accordance with 10 CFR 54.21(c)(1)(i) and the normal and alternate charging lines in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

4.3.4.1.2 Staff Evaluation

During its review, the staff noted that the applicant is using a linear basis to project the cumulative cycles for the design basis transients to the end of the period of extended operation. The staff accepted the applicant's methodology in SER Section 4.3.1. The staff determined that the applicant revised the auxiliary spray lines fatigue analyses to reduce the original design basis transients from 10 to 5 inadvertent auxiliary spray transients, in response to GL 88-08, in 1999.

The staff confirmed that the 60-year projected cycles for the inadvertent auxiliary spray transient are 2 and 3 for Units 1 and 2, respectively, from LRA Tables 4.3.1-3 and 4.3.1-4. These projected cycle counts are less than the design basis of 10 for this transient. Based on this review, the staff finds that the applicant has provided an acceptable basis for demonstrating that the metal fatigue TLAA for the auxiliary spray lines are acceptable in accordance with 10 CFR 54.21(c)(1)(i) because the staff has confirmed that the number of auxiliary spray transient occurrences, as projected through the period of extended operation, will be bounded by the number of occurrences allowed under the applicant's design basis for this transient.

The staff's review of the normal and alternate charging lines determined that the applicant previously revised the charging lines fatigue analyses to include additional transients, in response to GL 88-08. During aging management program (AMP) audit interviews of the applicant's technical staff, the NRC staff clarified that additional transients incorporated into the charging lines fatigue analyses were included in LRA Tables 4.3.1-3 and 4.3.1-4. These transients are inadvertent auxiliary spray to pressurizer and inadvertent safety injection transients. To address the reactor coolant environmental effects, the applicant re-evaluated the charging lines (the charging to pipe weld) fatigue analysis. The applicant presented the results of this re-evaluation in LRA Section 4.3.7. The staff's evaluation and acceptance of the fatigue analyses for the charging lines is documented in SER Section 4.3.7.

4.3.4.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of supplementary ASME Code Section III, Class 1 piping and components fatigue analyses in LRA Section A.4.3.4. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's metal fatigue TLAA for the supplementary ASME Code Section III, Class 1 piping and components is adequate.

4.3.4.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the auxiliary spray lines remain valid for the period of extended operation. The staff's evaluation and acceptance of the charging lines are documented in SER Section 4.3.7. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation for the supplementary ASME Code Section III, Class 1 piping and components, as required by 10 CFR 54.21(d).

4.3.4.2 NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification

4.3.4.2.1 Summary of Technical Information in the Application

LRA Section 4.3.4 summarizes the evaluation of supplementary ASME Code Section III, Class 1 piping and component fatigue analysis for the period of extended operation. This TLAA is based on the analysis in response to NRC Bulletin 88-11. The applicant stated that Units 1 and 2 piping systems were originally designed in accordance with the ASA/USAS B31.1 piping code, however, a number of updated fatigue analyses have been performed for some piping systems and components to address transients that have been identified based on industry practice that were not originally considered.

The applicant further stated that these transients include those associated with thermal stratification of the pressurizer surge line as described in NRC Bulletin 88-11. LRA Section 4.3.4 also stated that a plant-specific WESTEMS™ model was developed for the pressurizer and surge line to evaluate the effects of pressurizer insurge and outsurge transients and surge line stratification on the pressurizer surge nozzle safe end to pipe weld and the surge line hot leg nozzle. These results were also used in the evaluation of the reactor water environmental effects on the surge line.

In this TLAA, the applicant dispositioned the TLAA for the pressurizer surge line based on the criterion in 10 CFR 54.21(c)(1)(ii).

4.3.4.2.2 Staff Evaluation

The staff's review of the pressurizer surge line thermal stratification determined that the applicant previously evaluated the effects of thermal stratification and plant-specific transients on the pressurizer surge line, in response to GL 88-11. This evaluation demonstrated that the surge line weld to the pressurizer surge nozzle is a controlling location for the pressurizer surge line. To address reactor coolant environmental effects, the applicant re-evaluated the pressurized surge line (the pressurizer surge line hot leg nozzle and pressurizer nozzle to safe end weld) using ASME B&PV Code Section III, Class 1 fatigue analysis. The applicant presented the results of this re-evaluation in LRA Section 4.3.7.

During its review of the LRA, the staff identified concerns regarding the results determined by the WESTEMS™ program as a part of the ASME Code fatigue evaluation process. For example, Westinghouse's response to NRC questions regarding the AP1000 Technical Report (see Agencywide Document Access and Management System (ADAMS) Accession No. ML102300072, dated August 13, 2010) describes the ability of users to modify intermediate data (peak and valley stresses/times) used in the analyses. In addition, a response provided on August 20, 2010 (ADAMS Accession No. ML102350440), describes different approaches for summation of moment stress terms. These items can have significant impacts on calculated fatigue CUF. The staff issued an RAI requesting information on how WESTEMS™ was used in the Salem analyses, whether these issues apply to the Salem analyses, the environmentally-assisted fatigue (EAF) analyses, and the differences between the stress models used in WESTEMS™ and the stress models used in the current governing analysis of record and the EAF analysis of record. The staff also requested a benchmarking evaluation to compare calculated stresses and CUF using WESTEMS™ to the same results from the initial design basis analyses of record. This was identified as Open Item OI 4.3.4.2-1. This Open Item was closed and its resolution is discussed in SER Section 3.0.3.2.18.

The staff's evaluation of the fatigue analyses for the pressurizer surge line is documented in SER Section 4.3.7.

4.3.4.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of supplementary ASME Code Section III, Class 1 piping and components fatigue analyses in LRA Section A.4.3.4. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, and the closure of Open Item OI 4.3.4.2-1, the staff concludes that the summary description of the applicant's metal fatigue TLAA for the supplementary ASME Code Section III, Class 1 piping and components is adequate.

4.3.4.2.4 Conclusion

The staff's evaluation and acceptance of the pressurizer surge line are documented in SER Section 4.3.7. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation for the supplementary ASME Code Section III, Class 1 piping and components, as required by 10 CFR 54.21(d).

4.3.4.3 Salem Unit 1 Steam Generator Feedwater Nozzle Transition Piece

4.3.4.3.1 Summary of Technical Information in the Application

LRA Section 4.3.4 summarizes the evaluation of supplementary ASME Code Section III, Class 1 piping and component fatigue analysis for the period of extended operation. This TLAA is based on the replacement of the Unit 1 SGs. In this TLAA, the applicant stated that Units 1 and 2 piping systems were originally designed in accordance with the ASA/USAS B31.1 piping code, however, a number of updated fatigue analyses have been performed for some piping systems and components to address transients that have been identified based on industry practice that were not originally considered. The applicant also stated that, as a part of the Salem Unit 1 SG replacement, a new feedwater nozzle transition piece forging was designed in accordance with ASME B&PV Code Section III, Class 1.

In this TLAA, the applicant dispositioned the TLAA for the feedwater nozzle transition piece forging based on the criterion in 10 CFR 54.21(c)(1)(iii) for the period of extended operation using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

4.3.4.3.2 Staff Evaluation

The staff's review of the feedwater nozzle transition piece determined that hot standby operation transients were replaced with thermal stratification loadings in the updated fatigue analysis for the feedwater nozzle transition piece forging. For the remaining plant life of 15 cycles, the applicant assumed 800 hours of auxiliary feedwater flow per cycle, resulting in a design limit of 12,000 hours of auxiliary feedwater operation. The applicant stated that the thermal stratification loads are managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program, where the number of auxiliary feedwater flow operational hours will be tracked and compared to the design limit of 12,000 hours. However, the LRA does not provide sufficient information for the staff to determine how the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks and compares the design limit of 12,000 hours for the auxiliary feedwater flow operation, and which transients tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program will assure that the design limit of 12,000 hours for the auxiliary feedwater flow operation is not exceeded. By letter dated June 14, 2010, the staff issued RAI 4.3-04 requesting that the applicant justify why the enhancement of the Metal Fatigue of Reactor Coolant Pressure Boundary Program for tracking of the hourly operations of this transient is an acceptable basis to disposition this TLAA in accordance with 10 CFR 54.21(c)(1)(iii).

In its response dated July 13, 2010, the applicant stated that it has revised its management of the Salem Unit 1 SG feedwater nozzle transition piece and rather than manually tracking hours of the auxiliary feedwater pump during the period of extended operation, the applicant will use WESTEMS™ to automatically compute the CUF for the Unit 1 SG feedwater nozzle transition piece. The applicant further stated that a design limit will be determined for cumulative usage, based on auxiliary feedwater operation, at the transition piece as opposed to tracking the number of auxiliary feedwater flow operational hours. The applicant stated that the design limit is a CUF of 1.0. The applicant stated that all the design basis transients considered in the original analysis will remain the same and these transients are monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated that the hot standby transient was replaced with the thermal stratification loads, which are caused by the auxiliary feedwater pump. The applicant further stated that if the fatigue usage for this location approaches 80 percent of the design limit, the corrective action program will be initiated to evaluate the condition and determine corrective actions.

Based on its review, the staff finds the applicant's response to RAI 4.3-04 acceptable because the applicant has modified its approach for aging management based on the pump operation hours to CUF values and the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the cumulative usage design limit of 1.0 is not exceeded. During its review of the LRA, the staff identified concerns regarding the results determined by the WESTEMS™ program as a part of the ASME Code Section III fatigue evaluation. This concern was identified as Open Item OI 4.3.4.2-1 and its resolution is discussed in SER Section 3.0.3.2.18. The staff's concern with the issue on the use of WESTEMS™ as described in RAI 4.3-04 is resolved.

4.3.4.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of supplementary ASME Code Section III, Class 1 piping and components fatigue analyses in LRA Section A.4.3.4. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's metal fatigue TLAA for the supplementary ASME Code Section III, Class 1 piping and components is adequate.

4.3.4.3.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.1.1.3, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the feedwater nozzle transition piece forging intended functions 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 for the supplementary ASME Code Section III, Class 1 piping and components, as required by 10 CFR 54.21(d).

4.3.4.4 Salem Unit 1 Steam Generator Primary Manway Studs

4.3.4.4.1 Summary of Technical Information in the Application

LRA Section 4.3.4 summarizes the evaluation of supplementary ASME Code Section III, Class 1 piping and component fatigue analysis for the period of extended operation. This TLAA is based on the qualification of the SG primary manway studs for a longer life. In this TLAA, the applicant stated that Units 1 and 2 piping systems were originally designed in accordance with the ASA/USAS B31.1 piping code, however, a number of updated fatigue analyses have been performed for some piping systems and components to address transients that have been identified based on industry practice that were not originally considered. The applicant also stated that, as a part of the Unit 1 SG replacement, the design basis for Unit 1 SG manway studs was updated to include fatigue considerations.

In this TLAA, the applicant dispositioned the TLAA for the Salem Unit 1 SG manway studs based on the criterion in 10 CFR 54.21(c)(1)(i).

4.3.4.4.2 Staff Evaluation

The staff's review of the SG manway studs fatigue analysis determined that, as specified in the LRA, Westinghouse conducted a series of tests to qualify the SG manway studs for 40 years of plant operation. The staff also noted that, although LRA Section 4.3.4.4 indicated that the 60-year projected cycles for the Unit 1 SG manway studs were bounded by the number of cycles assumed in the 40-year design basis fatigue analysis, the LRA did not provide sufficient information to identify which transients were used in the design basis analysis and the 60-year fatigue analysis of the SG manway studs. By letter dated June 14, 2010, the staff issued RAI 4.3-03 requesting that the applicant identify what transients were used in the 40-year fatigue analysis of the SG manway studs and clarify whether limiting cycle numbers for these transients were equivalent to the design basis transient limits.

In its response dated July 13, 2010, the applicant stated that Westinghouse conducted a series of tests to qualify the SG manway studs for a 40-year life. The applicant further stated that these tests were performed for Westinghouse Model F SGs in accordance with ASME Code Section III, Appendix II, 1989 Edition. The applicant stated that the test parameters were determined by using the design transients from the general design specification for the Westinghouse Model F SG. The applicant stated that because the transients used for the fatigue qualification tests considered a larger population of SGs, the testing parameters included additional transients (i.e., reactor coolant pipe break, steam pipe break, operating basis earthquake (OBE), etc.). The applicant further stated that all of the 40-year design transients in the general design specification for Model F SGs were determined to bound the corresponding 40-year design transients for the Unit 1 SGs. The applicant stated that the 40-year design transients for the Unit 1 Model F SGs are bounded by those presented in LRA Table 4.3.1-3 and that there are no other 40-year design transients that are applicable to the Unit 1 Model F SG primary manway studs fatigue analyses that were not listed in LRA Table 4.3.1-3. The applicant further stated that the 60-year cycle projections contained in LRA Table 4.3.1-3 are bounded by the test parameters used for the primary manway stud fatigue qualification testing. The applicant also stated that Westinghouse concluded after fatigue testing that the CUF was less than 1.0. The applicant further stated that because the 60-year cycle projections are bounded by the test parameters, the 60-year projected CUF is also less than 1.0.

Based on its review, the staff finds the applicant's response to RAI 4.3-03 acceptable because: (1) the applicant indicated that the Steam Generator Primary Manway Studs have been fatigue tested in accordance with the ASME Code and (2) this fatigue testing bounds the design bases transient limits and the 60-year projected cycles are less than the design bases limits, which means that the fatigue testing also bounds the period of extended operation. The staff's concern described in RAI 4.3-03 is resolved.

4.3.4.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of supplementary ASME Code Section III, Class 1 piping and components fatigue analyses in LRA Section A.4.3.4. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's metal fatigue TLAA for the supplementary ASME Code Section III, Class 1 piping and components is adequate.

4.3.4.4.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.1.1.1, the staff concludes that the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(i), that the Unit 1 SG manway studs fatigue analyses remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation for the supplementary ASME Code Section III, Class 1 piping and components, as required pursuant to 10 CFR 54.21(d).

4.3.5 Reactor Vessel Internals Fatigue Analyses

4.3.5.1 Summary of Technical Information in the Application

LRA Section 4.3.5 summarizes the evaluation of reactor vessel internals for the period of extended operation. In this TLAA, the applicant stated that the Salem reactor vessel internals were designed and constructed prior to the development of ASME code requirements for core support structures, and the RCS functional design requirements were considered. The applicant also stated that the reactor vessel internals were implicitly designed for low cycle fatigue based upon the RCS design basis transients and were identified as a TLAA. In this TLAA, the applicant dispositioned the TLAA for reactor vessel internals fatigue analyses based on the criterion in 10 CFR 54.21(c)(1)(i).

4.3.5.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.3.5 for reactor vessel internals fatigue analyses against the acceptance criteria in SRP-LR Section 4.3.2.1.3 and the review procedures in SRP-LR Section 4.3.3.1.3 in order to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the reactor vessel internals fatigue analyses remain valid for the period of extended operation.

During its review, the staff noted that LRA Section 4.3.5 states that the reactor vessel internals were designed based on the RCS design transient projections for 40 years. During the AMP audit and based on the additional information provided by the applicant as referenced in the Audit Report, the staff clarified that the RCS design transient projections for 40 years refer to the RCS design-basis transients. The staff reviewed the 60-year cycle projections, as summarized in LRA Tables 4.3.1-3 and 4.3.1-4, and confirmed that these projections were based on the projection methodology as described in SER Section 4.3.1. The staff further confirmed that, for transients used in the reactor vessel internals fatigue analyses, the 60-year projected number of transient cycles for the reactor vessel internals are bounded by the design basis number of cycles. Therefore, the staff concludes that the applicant has provided a valid basis for dispositioning the metal fatigue TLAA for the reactor vessel internals in accordance with the criterion in 10 CFR 54.21(c)(1)(i) because: (1) the applicant’s 60-year linear extrapolation basis for the transients in LRA Tables 4.3.1-3 and 4.3.1-4 bounds the actual trend in transient occurrences for the Salem units, and (2) the staff has confirmed that the 60-year transient occurrence projections for these components are bounded by the design-basis limit values listed for these transients.

4.3.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel internals fatigue analyses in LRA Section A.4.3.5.

On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's metal fatigue TLAA for the reactor vessel internal components is adequate.

4.3.5.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.1.3, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the metal fatigue TLAA for the reactor vessel internals remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation for the reactor vessel internal components, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.3.6 Spent Fuel Pool Bottom Plates Fatigue Analyses

4.3.6.1 Summary of Technical Information in the Application

LRA Section 4.3.6 summarizes the evaluation of fatigue on spent fuel pool (SFP) bottom plates for the period of extended operation. This TLAA is based on a response to a staff RAI dated February 26, 1996, for when an analysis was performed to show that the SFP liner and anchors would not experience significant deformations as a result of thermal loadings. Because the SFP liner and anchors were identified as a TLAA for the 40-year plant life, the applicant performed an evaluation of these components for the period of extended operation. The applicant further stated that based on these analyses, the resulting number of allowable cycles for the SFP liner bottom plates plant normal heatup and cooldowns is 1,638 cycles. This number of allowable cycles is much greater than the projected number of plant heatups and cooldowns (266 for Unit 1 and 312 for Unit 2).

The applicant also stated that a separate analysis of the SFP liner bottom plate and anchors determines a CUF of 0.00063 under upset conditions, based on one design-basis event (DBE) and 20 OBE cycles. The applicant projects 1 DBE and 2 OBEs for Unit 1, and 1 DBE and 3 OBEs for Unit 2.

The applicant stated that because the 60-year projected number of cycles used in fatigue analyses of the SFP liner and anchors remained bounded by the design basis number of cycles, the design basis fatigue analyses will remain valid for 60 years of operation. The applicant dispositioned the TLAA for fatigue of SFP bottom plates based on 10 CFR 54.21(c)(1)(i).

4.3.6.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.3.6 for fatigue of SFP bottom plates against the acceptance criteria in SRP-LR Section 4.3.2.1.3 and the review procedures in SRP-LR Section 4.3.3.1.3 in order to verify that the SFP liner and anchors fatigue analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- UFSAR Section 9.1.2, "Spent Fuel Pool"
- UFSAR Table 5.2-10, "Design Thermal and Loading Cycles – AREVA NP Model 61/19T SG – Unit 2"
- UFSAR Table 5.2-10a, "Design Thermal and Loading Cycles – Model F SG – Unit 1"
- 10 CFR 50.55a, "Codes and Standards"

During its review, the staff noted that the applicant's 60-year cycle projections for plant heatups and cooldowns were based on the projection methodology accepted by the staff in SER Section 4.3.1. The staff further confirmed that the total number of 60-year projected cycles is 266 and 312 for Units 1 and 2, respectively, and would remain bounded by the 1,638 allowable cycle limit.

Since the plant has experienced neither an OBE nor a DBE, the staff further confirms that the 60-year cycle projections would remain bounded by 1 DBE and 20 OBE cycles. Therefore, the staff concludes that the applicant's design transient cycle projection provides a conservative estimate of the number of transients occurring through the period of extended operation because the transients are not expected to go over the design-basis value based on the observed operating experience.

4.3.6.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the SFP bottom plates fatigue analyses in LRA Section A.4.3.6. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes that the summary description of the applicant's actions to address the SFP bottom plates fatigue analyses is adequate.

4.3.6.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.1.3, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), the analyses for the SFP bottom plate liner and anchors will 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 for the SFP bottom plate liner and anchors, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.3.7 Environmentally-Assisted Fatigue Analyses

4.3.7.1 Summary of Technical Information in the Application

LRA Section 4.3.7 summarizes the evaluation of EAF for the period of extended operation. This TLAA evaluates the effects of the RCS environment on the following fatigue life representative components that are identified in NUREG/CR-6260 for older vintage Westinghouse plants:

- reactor vessel shell and lower head
- reactor vessel inlet and outlet nozzles
- surge line
- charging system nozzle
- safety injection system nozzle
- residual heat removal system Class 1 piping

In this TLAA, the applicant stated that the plant-specific components were identified for the NUREG/CR-6260 sample locations and EAF calculations followed the guidance of NUREG/CR-6583 for components made of carbon and low-alloy steels and the guidance of NUREG/CR-5704 for components made of austenitic stainless steel. The applicant further stated that no CUF values considering environmental effects will exceed the code limit of 1.0 for 60 years of operation. In this TLAA, the applicant dispositioned the TLAA for EAF based on 10 CFR 54.21(c)(1)(ii).

4.3.7.2 Staff Evaluation

The staff reviewed the TLAAs in LRA Section 4.3.7 for EAF against the acceptance criteria in SRP-LR Section 4.3.2.2 and the review procedures in SRP-LR Section 4.3.3.2 in order to verify, in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses for the NUREG/CR-6260 sample locations have been projected to the end of the period of extended operation.

During its review, the staff determined that, using plant-specific design fatigue results, the applicant identified the plant-specific components and limiting components locations for the NUREG/CR-6260 sample locations and performed EAF calculations for these components to evaluate the effects of the RCS environment on fatigue life. However, the LRA does not provide sufficient information on the methodology used in determining the plant-specific components and limiting component locations for the NUREG/CR-6260 sample locations. By letter dated June 14, 2010, the staff issued RAI 4.3-05 requesting that the applicant justify the methodology, assumptions, component locations, and results that the applicant included in the EAF evaluation for the LRA.

In its response dated July 13, 2010, the applicant provided the methodology used to determine the Salem plant-specific locations that bound the locations provided in the NRC guidance document NUREG/CR-6260.

For the reactor vessel shell and lower head, the applicant stated that it selected the core support guide welds as the limiting component based on guidance provided in Section 5.5.1 of NUREG/CR-6260. The applicant further stated that the controlling fatigue location is the outer corner of the weld that connects the core support guide to the reactor vessel inner wall. For the reactor vessel inlet and outlet nozzles, the applicant selected the reactor vessel inlet and outlet nozzles as the limiting components based on the guidance provided in Section 5.5.2 of NUREG/CR-6260. The applicant further stated that the controlling fatigue location is the outside surface of the nozzle-to-shell juncture. For the pressurizer surge line, the applicant stated that it evaluated fatigue in WCAP-12913, “Structural Evaluation of Salem Nuclear Plant Units 1 and 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification,” Revision 1. The applicant further stated that additional fatigue analysis was conducted for the pressurizer lower head and surge nozzles in WCAP 16194, “Evaluation of Pressurizer Insurge/Outsurge Transients for Salem Units 1 and 2,” Revision 0. The applicant stated that it used both these fatigue calculations and the information provided in NUREG/CR-6260 Section 5.5.3 to select the surge line hot leg nozzles as a limiting component for the pressurizer surge line. For the RCS piping charging system nozzles, the applicant stated that both the normal and alternating charging nozzles were chosen based on the guidance provided in NUREG/CR-6260 Section 5.5.4. The applicant further stated that it developed a detailed model of the nozzles and applied a stress analysis for the nozzles and connections to determine the exact limiting locations. The staff noted that this limiting location is the weld that connects the nozzle to the charging line piping. For the RCS piping safety injection nozzles, the applicant stated that it reviewed the safety injection system nozzles connected to the RCS cold leg based on the guidance provided in NUREG/CR-6260 Section 5.5.5. Based on this review, the applicant stated that the 1.5-inch boron injection tank nozzles were selected to represent this location. The applicant further stated that it developed a detailed model of the 1.5-inch boron injection tank nozzles and applied a stress analysis, which determined the fatigue controlling location was the boron injection tank piping region at the socket weld that connects the nozzle to the safety injection line piping. The applicant stated that for the residual heat removal system Class 1 piping, it used guidance in NUREG/CR-6260 Section 5.5.6 to review the residual heat removal system Class 1 piping, specifically the letdown path and return path to the RCS primary loop. Based on this review, the applicant stated it determined the 10-inch accumulator/residual heat removal injection cold leg nozzles to be the limiting fatigue location. The applicant further stated that it developed a detailed model and applied stress analyses for the 10-inch accumulator/residual heat removal injection cold leg nozzles and their connections to determine that the controlling fatigue location is the weld that connects the accumulator nozzle to the residual heat removal line piping.

The applicant responded to the question on the assumption used for the 60-year EAF calculations by first generating the 60-year CUF for the six sample locations listed in LRA Tables 4.3.7-1 and 4.3.7-2 and then applying the environmental fatigue life correction factor, F_{en}. The first assumption the applicant made was that the 40-year NSSS transient design cycles and auxiliary transient design cycles, or their respective 60-year projected number of cycles, would bound the actual number of cycles experienced during the period of extended operation. The applicant stated that it will validate the basis for this assumption by implementing the Metal Fatigue of Reactor Coolant Pressure Boundary Program to monitor transients and use the WESTEMS™ code to compute the cumulative fatigue at select NUREG/CR-6260 sample locations to ensure that the 60-year CUF values remain less than the design limit.

In the applicant’s response to the request for the assumptions used in the F_{en} calculations, the applicant stated it used the NUREG/CR-6583 and NUREG/CR-5704 methodologies to evaluate the environmental effects on carbon, low-alloy, and stainless steels. For low-alloy steel components, the applicant stated that it set both the temperature and oxygen content parameter to zero, which will maximize the F_{en} value at 2.532 for low-alloy steel components. For stainless steel components, it assumed that the oxygen content was less than 0.05 parts per million (ppm), which is based on normal operations of less than 5 ppb. The applicant further stated that it reviewed the dissolved oxygen data, which indicated that the dissolved oxygen content was less than 0.05 ppm since 2000, except for short periods of time during start-up and shutdown conditions. To determine the strain rate, the applicant stated it used an integrated method known as the modified rate approach. The applicant also stated that transient total stress time histories were used to determine the corresponding strain rates of the tensile producing portion of the stress cycle for the different fatigue pairs for all of the applicable analyzed transients.

The staff notes that the applicant's response did not specify the dissolved oxygen data prior to 2000 and that it is not clear whether the applicant's primary water chemistry specifications maintained dissolved oxygen less than 0.05 ppm since initial plant start-up. The staff notes that if there were extended periods of time, prior to 2000, in which the applicant operated with dissolved oxygen greater than 0.05 ppm, the assumptions used in the determination of the F_{en} value for carbon and low-alloy steels may not be valid. This is important to the carbon and low-alloy steel components because a dissolved oxygen content greater than 0.05 ppm can increase the F_{en} value. The staff notes that the assumption of less than 0.05 ppm dissolved oxygen is conservative when determining the F_{en} value for stainless steel because it increases the F_{en} value. The staff identified this as Open Item OI 4.3.4.2-1.

Regarding the question whether the critical fatigue locations include nickel alloys, the applicant stated that none of the six critical fatigue locations include nickel alloy materials and that low-alloy steel is used to construct the components for the critical fatigue locations associated with the reactor vessel shell and lower head and reactor vessel inlet and outlet nozzles. The applicant also stated that stainless steel is used in the construction of the critical fatigue locations associated with the: (1) pressurizer surge line nozzle, (2) RCS piping charging system nozzles, (3) RCS piping system safety injection nozzles, and (4) residual heat removal system Class 1 piping.

In response to the question requesting if there are other plant-specific locations that may be more limiting than those identified in NUREG/CR-6260, the applicant stated the selection of the locations are compliant with NUREG/CR-6260 and the determination of the limiting locations was presented in response to the first request of this RAI. The applicant stated that because the locations are compliant with NUREG/CR-6260 and the limiting locations were identified and evaluated, no other plant-specific locations were required to be identified and evaluated for EAF. The staff notes that SRP-LR Section 4.3.2.2 states that the critical components should include, as a minimum, those selected in NUREG/CR-6260. Furthermore, the staff notes that there may be more limiting plant-specific locations (e.g., locations with a higher CUF value). It is not clear to the staff whether these locations were also considered or are the locations selected by the applicant for EAF evaluations, the limiting plant-specific locations (e.g., locations with a higher CUF value) for the plant. The staff was concerned whether the applicant verified that the locations per NUREG/CR-6260 are bounding as compared to other plant-specific locations (e.g., locations with a higher CUF value). This was also identified as part of Open Item OI 4.3.4.2-1.

By letter dated November 22, 2010, the staff issued RAI 4.3-08 to address both portions of Open Item OI 4.3.4.2-1. RAI 4.3-08, Part 1 requested the applicant to confirm and justify that the locations selected for EAF analyses, consistent with NUREG/CR-6260, are the most limiting and bounding for the plant. Furthermore, if these locations are not the most limiting and bounding for the plant, clarify the locations that require an EAF analysis and the actions that will be taken for these additional locations. If the most limiting location consists of nickel alloy, the NUREG/CR-6909 methodology for nickel alloy will be used. The staff also requested in RAI 4.3-08, Part 2 that the applicant justify the statement, "Fen is maximized when these two terms are set equal to zero" made in response to RAI 4.3-05. Finally, the staff requested in

Part 3 that the applicant clarify whether dissolved oxygen content has always been maintained less than 0.05 ppm since initial plant start-up, and provide justification to support this clarification. If not, justify why the Fen values provided in LRA Tables 4.3.7-1 and 4.3.7-2 do not account for these periods of time in which dissolved oxygen content was not maintained less than 0.05 ppm, including the "short periods of time during start-up and shutdown conditions."

In its response to Part 1, dated December 21, 2010, the applicant committed (Commitment No. 52) to the following:

> [It] will perform a review of design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 based locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Salem plant configuration. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. If any of the limiting locations consist of nickel alloy, NUREG/CR-6909 methodology for nickel alloy will be used in the evaluation.

Based on its review, the staff finds the applicant's responses to RAI 4.3-05; RAI 4.3-08, Part 1; and Commitment No. 52 acceptable because: (1) the applicant will review its design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 based locations are the limiting locations for its plant-specific configuration; (2) if more limiting locations are identified, the applicant will perform EAF analyses for the most limiting location; (3) if any of the limiting locations consist of nickel alloy, the NUREG/CR-6909 methodology for nickel alloy will be used in the evaluation; (4) NUREG/CR-6909 will be used for determining a conservative F_{en} factor for any new nickel-alloy components that require EAF analysis; and (5) Commitment No. 52 is consistent with the recommendations in SRP-LR Sections 4.3.2.2 and 4.3.3.2, and GALL AMP X.M1, to consider environmental effects for the NUREG/CR-6260 locations, at a minimum. The staff's concerns described in RAI 4.3-05 and RAI 4.3-08, Part 1 are resolved, and this portion of Open Item OI 4.3.4.2-1 is closed.

In its response to Part 2, dated December 21, 2010, the applicant clarified that the two terms in the statement, "F_{en} is maximized when these two terms are set equal to zero" referred to the correction temperature, T, and the transformed oxygen content parameter, O*. The staff noted that during the applicant's review, it identified a typographical error in its response to RAI 4.3-05 (Part 3), dated July 13, 2010, and amended the term "0.001124T" to "0.00124T." The staff reviewed Equation 6.5b of NUREG/CR-6583 and confirmed that the use of the term "0.00124T" is correct. The applicant stated that it agrees that the above statement is not accurate for all situations, particularly when a negative transformed total strain rate, ε*, is used and the resultant F_{en} value would exceed 2.532.

The applicant stated that it applied a zero term for transformed dissolved oxygen content, O*, making the third term (0.101S*T*O* ε*) of Equation 6.5b from NUREG/CR-6583 equal to zero for its plant-specific environmental fatigue analyses, since the dissolved oxygen content was assumed to be less than 0.05 ppm. The staff noted that the applicant's response to RAI 4.3-08, Part 3 further explains this assumption. The staff's review of RAI 4.3-08, Part 3 is documented below, in SER Section 4.3.7.2. Furthermore, a conservative value of zero was used for the second term (0.00124T) in Equation 6.5b. The applicant stated that the statement, "F_{en} is maximized when these two terms are set equal to zero" is not accurate for analyses other than its plant-specific environmental fatigue analyses. The staff finds that setting the second term (0.00124T) in Equation 6.5b to zero is acceptable because it yields a larger F_{en} factor, which is more conservative. The staff noted that the response to RAI 4.3-05 (Part 3), dated July 13, 2010, was amended to remove the statement, "F_{en} is maximized when these two terms are set equal to zero" and finds this acceptable because the statement is not accurate for all situations of transformed dissolved oxygen content, transformed total strain rate, transformed temperature, and transformed sulfur content.

In its response to Part 3, dated December 21, 2010, the applicant clarified that during Modes 1 (Power Operations) and 2 (Startup), where the RCS is greater than or equal to 177 °C (350 °F) and reactivity condition (K_{eff}) is greater than 0.99, the dissolved oxygen concentrations are always less than 0.05 ppm (50 ppb), specifically, less than 0.005 ppm (5 ppb) as determined from the RCS quarterly chemistry data since 2000. The applicant stated that the reason for the extremely low dissolved oxygen levels is due to the RCS environment containing a hydrogen concentration of a minimum of 25 cc/kg (cubic centimeters per kilogram), as specified for Westinghouse PWRs to keep the oxygen level in the RCS below the limit of detection (5 ppb). The applicant stated that it had this specification limit of RCS hydrogen imposed since original start-up of the units. The staff finds it reasonable, during Modes 1 and 2, since the applicant has operated with a minimum of 25 cc/kg of RCS hydrogen, that dissolved oxygen was always less than 0.05 ppm (50 ppb), specifically, less than 0.005 ppm (5 ppb) since original start-up of the units.

The staff reviewed Equation 6.5b for low-alloy steels from NUREG/CR-6583 and noted that the transformed temperature, T*, is set to zero when the RCS temperature is less than 150 °C (302 °F), which negates the contribution from dissolved oxygen in this equation. The applicant stated that any dissolved oxygen values exceeding 0.05 ppm (50 ppb) during Mode 5 (Cold Shutdown – RCS temperature less than 93 °C (200 °F)) and Mode 6 (Refueling – RCS temperature less than 60 °C (140 °F)) do not contribute to EAF due to the low RCS temperatures. The staff finds that the transformed oxygen content parameter, O*, in Equation 6.5b can be ignored in Modes 5 and 6 because the RCS temperature during these modes does not exceed the threshold of 150 °C (302 °F) described in NUREG/CR-6583, therefore, setting the term "$0.101S^*T^*O^*\,\varepsilon^*$" equal to zero.

The applicant stated that there are possible short periods of time where the RCS dissolved oxygen levels can exceed 0.05 ppm, while the RCS temperatures exceed 150 °C (302 °F) for carbon and low-alloy steel. These short periods of time are during Mode 3 (Hot Standby – RCS temperature greater than 177 °C (350 °F) and K_{eff} is less than 0.99) and Mode 4 (Hot Shutdown – RCS temperature greater than 93 °C (200 °F) but less than 177 °C (350 °F) and K_{eff} is less than 0.99). The applicant stated that during the time when the RCS is heating from 150 °C (302 °F) (Mode 4) to 177 °C (350 °F) (Mode 3), or cooling from 177 °C (350 °F) (Mode 3) to 150 °C (302 °F) (Mode 4), the RCS dissolved oxygen levels could exceed 0.05 ppm (50 ppb), but are less than or equal to 0.10 ppm (100 ppb). Furthermore, the oxygen control is attained through hydrazine addition to the primary system. The applicant stated that the short periods of time are less than 24 hours per plant heatup and are less than 8 hours per plant cooldown.

The staff noted that the projected number of heatups and cooldowns for Unit 1 are 133 and 133, respectively, and 157 and 155 for Unit 2, respectively. The applicant stated that for additional conservatism, the 40-year NSSS design specification of 200 heatups and 200 cooldowns is multiplied by a time period of 24 hours for the heatup event and 8 hours for the cooldown event, which resulted in 6,400 hours. Furthermore, the projected effective full power hours for each unit is obtained by multiplying the effective full power years of 50 by 8,760 hours in a year, or 438,000 hours. The applicant determined that the percentage of time that the RCS temperature will be heating from 150 °C (302 °F) to 177 °C (350 °F), and cooling from 177 °C (350 °F) to

150 °C (302 °F) is less than 1.5 percent of the total operating time. The applicant determined an adjusted F_{en} value, which considers the dissolved oxygen level effect during Mode 3 and Mode 4, and noted that it results in a 0.4 percent increase in the CUF_{EAF} for the Units 1 and 2 reactor vessel inlet nozzles which are fabricated from low-alloy steel.

The staff finds that the short periods of time when the dissolved oxygen levels can exceed 0.05 ppm does not have a significant impact to the overall F_{en} value because the duration of time that both units operate with dissolved oxygen levels in excess of 0.05 ppm will conservatively be 1.5 percent of the total operating time after 60 years of operation and the resultant increase in F_{en} value is approximately 0.4 percent, which is negligible. The staff noted that this is applicable for both carbon and low-alloy steel components.

The applicant stated that it has not changed the chemistry control with regards to oxygen control in the RCS when the temperature is greater than 150 °C (302 °F) since original plant start-up, therefore, the values observed in the past 10 years (2000 to 2010) are representative of past operations. Furthermore, it will continue to and is committed to maintain its primary water chemistry, including the previously discussed limitations on dissolved oxygen, through the Water Chemistry Program, which incorporates Electric Power Research Institute (EPRI) guidelines.

Based on its review, the staff finds the applicant's response to RAI 4.3-8, Parts 2 and 3 acceptable because: (1) the applicant confirmed that it has always maintained dissolved oxygen levels less than 0.05 ppm since initial plant start-up during Modes 1 and 2; (2) the impact of dissolved oxygen levels greater than 0.05 ppm but less than or equal to 0.10 ppm, during Modes 3 and 4, on the F_{en} value are negligible, as described above; (3) the impact of dissolved oxygen levels greater than 0.05 ppm during Modes 5 and 6, when the temperature is less than 150 °C (302 °F), do not need to be considered, as described above; (4) the applicant will continue to maintain its primary water chemistry during the period of extended operation; and (5) the applicant justified that a F_{en} value of 2.532 for low-alloy steel components is conservative, based on its plant-specific operating conditions. The staff's concerns described in RAI 4.3-05 and RAI 4.3-08, Parts 2 and 3 are resolved, and this part of Open Item OI 4.3.4.2-1 is closed.

The staff also noted that, in LRA Section 4.3.7, the applicant stated that the fatigue analyses for the NUREG/CR-6260 sample locations have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The staff noted, however, that LRA Section B.3.1.1 indicated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced to address the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant, as identified in NUREG/CR-6260. Therefore, it was not evident to the staff whether the applicant had chosen to use its Metal Fatigue of Reactor Coolant Pressure Boundary Program as the basis for accepting the EAF analysis TLAA, in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii), and for managing the effects of environmental fatigue on the intended functions of the applicant's NUREG/CR-6260 sample locations during the period of extended operation. Therefore, in a letter dated June 14, 2010, the staff issued RAI 4.3-06 requesting that the applicant clarify: (1) how the Metal Fatigue of Reactor Coolant Pressure Boundary Program would be used to monitor the effects of the reactor coolant environment on the metal fatigue analyses for the plant's critical NUREG/CR-6260 locations, and (2) whether the AMP would be used to disposition the EAF analyses for these components in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii).

In its response dated July 13, 2010, the applicant stated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program addresses the effects of the reactor coolant environment on component fatigue life on fatigue limiting locations. The applicant further stated that it would revise site procedures to include the effects of the reactor coolant environment for each of the six locations discussed in LRA Section 4.3.7 in a periodic fatigue monitoring report. In addition, the applicant modified the LRA to indicate that the aging of these fatigue limiting locations will be managed by 10 CFR 54.21(c)(1)(iii) using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Based on its review, the staff finds the applicant's response to RAI 4.3-06 acceptable because the Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors the transients to ensure that the CUF considering environmental effects remains below the design basis of 1.0. The staff finds this an appropriate approach because the applicant has modified its LRA to indicate that the aging of these fatigue limited locations is managed in accordance with 10 CFR 54.21(c)(1)(iii). The staff's concern described in RAI 4.3-06 is resolved.

4.3.7.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of EAF analyses in LRA Section A.4.3.7. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.3.3.3, the staff concludes, with the closure of Open Item OI 4.3.4.2-1, that the summary description of the applicant's actions to address EAF analyses is adequate.

4.3.7.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.3.3.2, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed 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), and, therefore, is acceptable.

4.4 Other Plant-Specific Analyses

4.4.1 Reactor Vessel Underclad Cracking Analyses

4.4.1.1 Summary of Technical Information in the Application

The applicant performed the RPV underclad cracking analyses for the period of extended operation for Units 1 and 2, using the Westinghouse Owners' Group (WOG) topical report WCAP-15338-A, Revision 0, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants." The projected 60-year design cycles and transients for Units 1 and 2 are reported in LRA Tables 4.3.1-3 and 4.3.1-4, respectively. The number of design cycles and transients assumed in the WCAP-15338-A, Revision 0 analysis bound the numbers of design cycles and transients projected for 60 years of operation presented in LRA Tables 4.3.1-3 and 4.3.1-4. Therefore, Action Item 1 in the SE dated September 25, 2002, for WCAP-15338-A, Revision 0 is addressed. Further, a summary of this TLAA evaluation is provided in the UFSAR supplement for license renewal. Therefore, Action Item 2 in the SE for WCAP-15338-A, Revision 0 is also addressed. The applicant dispositioned the TLAA related to the underclad cracking analyses in accordance with 10 CFR 54.21(c)(1)(i).

4.4.1.2 Staff Evaluation

Underclad cracks were first discovered in October 1970 during examination of the Atucha RPV. They have been reported to exist only in SA-508, Class 2 RPV forgings manufactured with a coarse grain microstructure and clad by high heat input submerged arc welding processes. The SE for a WOG topical report to address this issue (WCAP-15338-A, Revision 0) specified two action items for applicants. Action item 1 states:

- The applicant is to verify that its plant is bounded by the WCAP-15338 report. Specifically, the applicant is to indicate whether the number of design cycles and transients assumed in the WCAP-15338 analysis bounds the number of cycles for 60 years of operation of its RPV.

Action item 2 states:

- Section 54.21(d) of 10 CFR requires that the UFSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants referencing the WCAP-15338 report for the RPV components shall ensure that the evaluation of the TLAA is summarily described in the UFSAR supplement.

LRA Tables 4.3.1-3 and 4.3.1-4 provide projected 60-year cycles for the design transients of Units 1 and 2. Also provided in these tables are NSSS design transients and cycles which were used in the fatigue analyses described in the WCAP-15338-A. For each design transient, the staff verified that the projected number of cycles for 60 years for each unit is bounded by the corresponding NSSS design limit and, therefore, Action Item 1 is addressed by the applicant appropriately.

Regarding Action Item 2, the applicant provided a summary description of its evaluation of the TLAA in UFSAR Section A.4.4.1, meeting the requirement described in Action Item 2. Hence, the staff agrees with the applicant that the existing RPV underclad cracking analysis in WCAP-15338-A is applicable to Salem Units 1 and 2.

4.4.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of RPV underclad cracking in LRA Section A.4.4.1. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.7.3.1.1, the staff concludes that the summary description of the applicant’s actions to address RPV underclad cracking is adequate.

4.4.1.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.7.3.1.1, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the WCAP-15338-A analysis for RPV underclad cracking remains valid for the period of extended operation and applicable to Units 1 and 2. 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), and, therefore, is acceptable.

4.4.2 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses

4.4.2.1 Summary of Technical Information in the Application

LRA Section 4.4.2 discusses RCP flywheel fatigue crack growth analyses. The applicant stated that Westinghouse Topical Report WCAP-14535A, “RCP Flywheel Inspection Elimination,” includes a fatigue crack growth analyses that has been identified as a TLAA. The applicant further stated that the purpose of the report was to provide an engineering basis for elimination of RCP flywheel inservice inspection (ISI) requirements for all operating Westinghouse plants and certain Babcock and Wilcox plants. The applicant also stated that the number of cycles (pump starts and stops) used in this report was 6,000 for a 60-year plant life and that crack growth was shown to be negligible from exposure to these 6,000 cycles.

In LRA Tables 4.4.2-1 and 4.4.2-2, the applicant provided the current and 60-year projected number of RCP start/stop cycles. Based on data obtained from Salem Cycle Counting records to date and projecting the count to the 60-year end of life, the applicant concluded that the 60-year projection of RCP start/stop cycles ranges from 501 to 661 for the four Unit 1 RCPs. Similarly, the applicant concluded that the 60-year projection ranges from 558 to 703 for the four Unit 2 RCPs. The applicant concluded that the projected number of RCP starts and stops is not expected to exceed 6,000 cycles during the period of extended operation. The applicant dispositioned this flywheel TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.4.2.2 Staff Evaluation

SRP-LR Section 4 does not list RCP flywheel fatigue crack growth analyses as TLAAs that are generic to industry LRAs. As a result, the staff reviewed LRA Section 4.4.2 against the acceptance guidance in SRP-LR Section 4.7.2.1 for dispositioning plant-specific TLAAs in accordance with 10 CFR 54.21(c)(1)(i). The staff reviewed LRA Section 4.4.2 to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

The staff notes that RG 1.14, Revision 1, "Reactor Coolant Pump Flywheel Integrity" [August 1976], provides the staff's recommended acceptance criteria for material and minimum fracture toughness properties of SA 508, Classes 2 and 3, materials and SA 533 Grade B, Class 2, materials used in the fabrication of U.S. RCP flywheels. RG 1.14, Revision 1 also provides guidelines for performing structural integrity assessments of the RCP flywheels in U.S. light-water reactors, including assessments for ensuring the integrity of the flywheels against unacceptable fatigue-induced crack growth failures.

The applicant stated that the fatigue crack growth assessments are based on the number of start-stop cycles assumed in the design specifications for the pumps. Therefore, to meet the 10 CFR 54.21(c)(1)(i) acceptance criterion, the applicant indicated that it must demonstrate that the total number of RCP start-stop cycles, projected through the end of the periods of extended operation, will be bounded by the number of RCP start-stop cycles assumed in the fatigue crack growth analysis for the RCP flywheels.

The staff notes that the applicant is relying on the flaw growth analysis in the NRC-approved version of WCAP-14535 (ADAMS Legacy Library Accession No. 9601290393) as the TLAA for the RCP flywheels. The staff confirms that the NRC endorsed the methodology and results in this WCAP report for use in an SE dated September 12, 1996 (ADAMS Legacy Library Accession No. 9609230010). However, in the SE (Section 4.0), the staff concluded that the inspections of the flywheels should be performed even if all of the recommendations of RG 1.14, Revision 1 were met and that the inspections of the RCP flywheels should not be completely eliminated. It is not clear to the staff from the TLAA discussion whether the applicant intends to continue the ISI examinations of the RCP flywheels during the period of extended operation consistent with the position taken in the staff's SE of September 12, 1996, or whether the applicant is proposing to discontinue the ISI examinations of the RCP flywheels during the period of extended operation.

By letter dated March 27, 2010, the staff issued RAI 4.4.2-1 requesting that the applicant clarify whether the safety basis in the TLAA for the RCP flywheels is being used to justify elimination of the RCP flywheel examinations altogether, or whether the applicant intends to continue the ISI examinations of the RCP flywheels consistent with the NRC's SE on WCAP-14535, dated September 12, 1996. If ISI examinations will be performed during the period of extended operation, the staff also requested that the applicant justify what type of examinations will be performed on the RCP flywheels during the period of extended operation and the frequency that will be used for the examinations. Otherwise, the applicant was requested to justify its basis for discontinuing the ISI examinations of the RCP flywheels if ISI examinations will be discontinued during the period of extended operation.

In its response dated April 20, 2010, the applicant stated that Units 1 and 2 performed surface and volumetric examinations of all of the RCP motor flywheels in accordance with its respective TS requirements. The applicant further stated it has reviewed ISI flywheel inspection reports both prior to 1983, the period covered by the WCAP-14535-A report, and also from 1995 to present. The applicant also stated that: (1) the review of the flywheel surface and volumetric examinations for the RCP motor flywheels has found that all inspections to date had acceptable results, and (2) there were no indications in any of the ISI inspection reports that required a flaw evaluation to be submitted to the staff for evaluation as required by regulatory position C.4.b(5) of RG 1.14, Revision 1.

The applicant stated that in the staff's letter dated September 9, 2005, the staff approved and permitted Salem to increase the RCP flywheel inspection to 20 years. The applicant further stated that this inspection frequency extension was consistent with the Industry/Technical Specification Change Traveler TSTF-421, "Revision to RCP Flywheel Inspection Program (WCAP-15666)," as discussed in the PSEG Nuclear LLC letter to the staff dated September 27, 2004 (ADAMS Accession No. ML042790502). The applicant stated that the conclusions in WCAP-15666-A identify that the results from the WCAP-14535-A report remain valid and that the extension of the RCP motor flywheel ISI frequency from 10 to 20 years satisfies RG 1.174 criteria as an acceptable change.

The staff reviewed WCAP-14535-A and confirmed that 6,000 start-stop cycles were assumed for the fatigue flaw growth analysis. The staff also reviewed the applicant's response to RAI 4.4.2-1 related to the results of the surface and volumetric inspection of all the flywheels and notes that the applicant will perform surface and volumetric inspections every 20 years as accepted by the staff.

Based on its review, the staff finds the applicant's response to RAI 4.2.2-1 and the applicant's claim that the RCP flywheels will maintain their structural integrity during the period of the extended operation acceptable because: (1) the maximum number of start-stop cycles projected for 60 years (e.g., 661 start-stop cycles for Unit 1 and 703 start-stop cycles for Unit 2) have been demonstrated to be bounded by the 6,000 start-stop cycles limit assumed in the WCAP-14535-A fatigue flaw growth analysis, (2) WCAP-14535 has been endorsed for use in the staff's SE of September 12, 1996, (3) future inspections will be performed once every 20 years, and (4) in accordance with 10 CFR 54.21(c)(1)(i), the current analysis has been demonstrated to remain valid for the period of extended operation. The staff's concern described in RAI 4.4.2-1 is resolved.

4.4.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the RCP flywheel fatigue crack growth analysis in LRA Section A.4.4.2. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.7.3.1.1, the staff concludes that the summary description of the applicant's actions to address RCP flywheel fatigue crack analyses is adequate.

4.4.2.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.7.3.1.1, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the WCAP-14535-A for RCP flywheel fatigue crack analyses is applicable to Units 1 and 2 and remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.4.3 Leak-Before-Break Analyses

4.4.3.1 Summary of Technical Information in the Application

Appendix A, General Design Criterion 4, of 10 CFR Part 50 allows for the use of LBB methodology for excluding the dynamic effects of postulated ruptures in RCS piping. The fundamental premise of the LBB methodology is that the materials used in nuclear power plant piping are sufficiently tough that even a large through-wall crack would remain stable and would not result in a double-ended pipe rupture. Application of the LBB methodology is limited to those high-energy fluid systems not considered to be susceptible to failure from mechanisms such as corrosion, water hammer, fatigue, and thermal aging or indirectly from such causes as missile damage or the failure of nearby components. The analyses involved with LBB are considered TLAAs.

The applicant performed an LBB analysis for Salem primary coolant loop piping in 1993. The applicant has updated the original LBB analysis for 60 years including the impact of the SG snubber elimination program, SG replacement design change packages, 1.4 percent power uprate evaluation, the T_{avg} operating window, and the Mechanical Stress Improvement Process (MSIP) application at the reactor vessel primary nozzle locations. The applicant used the plant-specific geometry, operating parameters, loading, and material properties in the fracture mechanics evaluation. Since the piping systems also include cast austenitic stainless steel (CASS) piping components, the applicant determined the fracture toughness considering thermal aging for each affected component's heat of material for the fully-aged condition (applicable for the period of extended operation).

The applicant stated that the recent LBB analysis demonstrates that the previous LBB conclusions still remain valid, and the dynamic effect of the pipe rupture resulting from postulated breaks in the reactor coolant primary loop piping need not be considered in the Salem structural design basis for the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.4.3.2 Staff Evaluation

Pursuant to 10 CFR 54.21(c)(1)(i), the staff reviewed LRA Section 4.4.3 to verify that the applicant's TLAA of LBB analyses for the primary coolant loop piping remain valid for the period of extended operation. Pursuant to 10 CFR 54.21(c)(1)(iii), the staff verified that the effects of aging on the intended function of the subject piping will be adequately managed for the period of extended operation. The TLAA of the LBB analyses for the primary coolant loop piping pertain to thermal aging of the CASS components in the primary coolant loop piping and fatigue crack growth analyses of the subject piping because these two issues are time-dependent.

Although not part of the TLAA, the staff also reviewed the impact of primary water stress-corrosion cracking (PWSCC) on the subject piping to ensure that the LBB piping will maintain its structural integrity during the period of extended operation.

In RAI 4.4.3-1, the staff requested that the applicant reference the original LBB reports for the LBB-approved piping for both units and identify any other piping systems that have been approved for LBB. In its response dated February 1, 2010, the applicant stated that the original LBB analysis for Units 1 and 2 was documented under WCAP-13659, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Salem Generating Station Units 1 and 2," July 1993. The staff approved the original LBB analysis by letter dated May 25, 1994 (ADAMS Legacy Library Accession No. 9406080285). The applicant stated that WCAP-13659 is only applicable to the primary coolant loop piping and no other piping system has been requested for LBB at Salem Units 1 and 2.

<u>Cast Austenitic Stainless Steel Components</u>. In RAI 4.4.3-3, the staff asked the applicant to identify each of the CASS piping components that are part of the LBB-approved piping. In its response dated February 1, 2010, the applicant stated that the only CASS components located

within the primary loop piping system are the elbows in the hot leg, cross-over leg, and cold leg for each of the four loops for Units 1 and 2.

The TLAA of the CASS components centers on a determination of whether the bounding fracture toughness for the CASS material is used in its LBB evaluation because fracture toughness of CASS material reduces with time which reduces the CASS component's ability to resist crack propagation. The staff reviewed WCAP-13659 and found that the applicant appropriately considered thermal aging effects in the CASS elbows in the primary loop piping. The applicant analyzed the CASS elbows adjacent to the load critical locations in the primary loop in the LBB evaluation. For the CASS elbows, the applicant used the lower bound (conservative) fracture toughness and yield strength in WCAP-13659. The staff finds that the applicant has addressed satisfactorily the thermal aging embrittlement of the CASS elbows in its LBB evaluation. RAI 4.4.3-3 is resolved.

Fatigue Flaw Growth Analyses. The TLAA of the fatigue flaw growth analyses determines whether the transient cycles used in its fatigue crack growth calculation in the LBB evaluation are bounding for the period of extended operation.

The applicant stated that the number of design cycles assumed for pertinent transients in the LBB analyses bound the number of design cycles projected for 60 years of operation. In RAI 4.4.3-6, the staff asked the applicant to discuss how the design cycles assumed in the LBB analysis are verified to ensure that they bound the number of design cycles projected for 60 years of operation. In its response dated February 1, 2010, the applicant stated that the process for determining the 60-year cycle projections is described in LRA Section 4.3.1, subsection "60-Year Transient Projection Methodology." The results of the 60-year projections for each design transient are provided in the third column, "60-Year Projected Cycles," in LRA Tables 4.3.1-3 (Unit 1) and 4.3.1-4 (Unit 2). The 60-year LBB analyses use the NSSS design cycle limit for the transients that are listed in the fourth column, "NSSS Design Limit," of LRA Tables 4.3.1-3 and 4.3.1-4. The staff confirmed that the NSSS design cycle limit bounds the corresponding 60-year projected cycles for the transients used in the 60-year LBB analyses.

The staff requested that the applicant discuss how the LBB analyses are verified to demonstrate that they remain valid for the period of extended operation in RAI 4.4.3-7. In its response dated February 1, 2010, the applicant stated that Units 1 and 2 will implement a Metal Fatigue of Reactor Coolant Pressure Boundary Program, which continues to count cycles for each of the transients. An annual report summarizes the current cycles and compares the cumulative values for each of the design transients to the appropriate design limits. Implementation of this program is a commitment (Commitment No. 47) in LRA Appendix A, Section A.5.

The staff finds that the applicant has adequate procedures to monitor the transient cycles in both units and to verify that the actual plant transient cycles will not exceed the transient cycles used in the fatigue flaw growth analyses in the LBB evaluation. Therefore, the applicant has adequately addressed the TLAA of the fatigue flaw growth calculation. RAIs 4.4.3-6 and 4.4.3-7 are resolved.

Pipe loadings used in the LBB evaluation are not time-dependent and, therefore, are not changed with time. They will not affect the LBB results at the end of 60 years and are not part of the TLAA. However, Salem has implemented the SG snubber elimination program, SG replacement, power uprate, T_{avg} operating window, and the MSIP application. These system-wide modifications may affect pipe loadings on the primary coolant loop which may change the results of the original LBB evaluation. The applicant described a 60-year LBB analysis in LRA Section 4.4.3. In RAI 4.4.3-2, the staff asked the applicant to describe in detail the 60-year LBB analysis.

In its response dated February 1, 2010, the applicant stated that the report that contains the 60-year analysis is WCAP-16958-P, Revision 0, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Salem Generating Station Units 1 and 2 for the License Renewal Program," March 2009. The 60-year LBB analysis (WCAP-16958-P) is a plant-specific analysis for Salem Units 1 and 2 that was performed using the same methodology as that of the original LBB analysis (WCAP-13659). The applicant summarized the 60-year LBB analysis as follows:

(1) A fracture mechanics evaluation was performed using Salem Units 1 and 2 plant-specific geometry, operating parameters, loadings, and material properties. Inputs from SG snubber elimination, SG replacement, 1.4 percent power uprate, Tavg operating window, and MSIP application at the reactor vessel inlet and outlet nozzle locations were used in the 60-year LBB analyses for both Salem Units 1 and 2. MSIP has not yet been implemented on the Salem Unit 2 reactor vessel inlet nozzle locations.

(2) Through-wall leakage flaw sizes at the critical locations were determined for a leak rate of 10 gallons per minute (gpm), or 10 times the leakage detection system capability of 1 gpm for Salem Units 1 and 2 using the normal loads.

(3) Stability analyses by the limit load method, as discussed in Appendix A in WCAP-13659, were performed at the critical locations using the faulted loads. The stability analyses by J-integral method were performed using the faulted loads and considering the effects of thermal aging of the cast stainless steel material. A margin between the leakage flaw size and the critical flaw size of greater than or equal to 2 was demonstrated.

(4) The absolute summation method of faulted load combination was applied to the stability analyses. Since crack stability was demonstrated using the absolute summation method of faulted load combination, a margin of 1 on loads was demonstrated.

(5) Fatigue crack growth analyses for 60-year plant life were performed and the results were shown to be acceptable. The fatigue crack growth analyses are based on the Salem Units 1 and 2 generic NSSS design transients and cycles, which bound the 60-year cycles for each of the transients used in the 60-year LBB analyses.

The applicant concluded that all of the LBB margins were demonstrated through the period of extended operation. Therefore, the previous LBB conclusions still remain valid, and the dynamic effects of the pipe rupture resulting from postulated breaks in the reactor coolant primary loop piping need not be considered in the structural design basis of the Salem Units 1 and 2 through the period of extended operation.

The staff finds that the applicant has adequately addressed the impact of the SG snubber elimination program, SG replacement, power uprate, T_{avg} operating window, and the MSIP application on the LBB evaluation for the period of extended operation. RAI 4.4.3-2 is resolved.

The staff notes that nickel-based Alloy 600/82/182 material in the PWR environment has been shown to be susceptible to PWSCC. In RAI 4.4.3-4, the staff requested that the applicant: (1) identify any Alloy 82/182 weld metal and Alloy 600 components used in the primary coolant loop piping for both units, (2) discuss any measures (such as weld overlays or mechanical stress improvement) that have been or will be implemented to reduce the susceptibility of PWSCC in the primary coolant piping, and (3) discuss the inspection history and future inspection frequency of the Alloy 82/182 dissimilar metal butt welds.

In its response dated February 1, 2010, the applicant stated that for each of the Salem units, the four reactor vessel outlet nozzle-to-safe-end welds and the four reactor vessel inlet nozzle-to-safe-end welds are the only Alloy 82/182 welds located within the LBB-approved piping. The reactor vessel primary inlet nozzle connects the cold leg piping to the reactor vessel, and the outlet nozzles connect the reactor vessel to the hot leg piping. The applicant stated that there are no Alloy 600 components within the LBB-approved piping for Units 1 and 2.

The applicant stated that during the fall 2008 refueling outage, Unit 1 implemented MSIP at the four Alloy 82/182 reactor vessel inlet nozzle-to-safe-end welds and the four Alloy 82/182 reactor vessel outlet nozzle-to-safe-end welds to mitigate PWSCC.

The applicant stated that during the fall 2009 refueling outage, Unit 2 implemented MSIP at the four Alloy 82/182 reactor vessel outlet nozzle-to-safe-end welds to mitigate PWSCC. The Unit 2 four Alloy 82/182 reactor vessel inlet nozzle-to-safe-end welds were not mitigated using MSIP during the fall 2009 refueling outage. MSIP for these remaining welds is planned for a future Unit 2 refueling outage.

The inspection history and future inspection frequency for the Alloy 82/182 dissimilar metal butt welds is discussed below.

Salem Unit 1. The applicant examined the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds during the first and second ISI 10-year intervals, including volumetric (ultrasonic testing (UT)) and surface (dye penetrant testing (PT)) examinations. Several of the weld UT examinations documented recordable indications. All of these indications were evaluated against the ASME Code Section XI, IWB-3500 acceptance criteria and all welds were found acceptable. No indications were documented during the PT examinations.

During the current third ISI 10-year interval, the applicant examined the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds by bare metal visual (BMV) examinations during the fall 2005 refueling outage in accordance with Materials Reliability Program (MRP) Letter 2004-05, “Needed Action for Visual Inspection of Alloy 82/182 Butt Welds and Good Practice Recommendations for Weld Joint Configurations,” April 2, 2004. The applicant stated that no evidence of leakage was identified.

The applicant also examined the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds during the fall 2008 refueling outage by phased array UT in accordance with the ASME Code Section XI, 1998 Edition through 2000 Addenda. Of the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds, only one weld had a flaw whose size exceeded the acceptance criteria of the 1998 Edition through 2000 Addenda of the ASME Code Section XI, IWB-3500 acceptance criteria. This flaw is located in the reactor vessel No. 14 outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt weld. This flaw was determined to be connected to the inside diameter surface. The applicant evaluated the flaw for continued service as required by IWB-3600 of the ASME Code Section XI, 1998 Edition through 2000 Addenda using the Westinghouse Flaw Evaluation Handbook. The applicant found the flaw acceptable for continued operation for up to 36 months without the need for repair or mitigation. However, the applicant applied MSIP at the reactor vessel No. 14 outlet nozzle region during the same (fall 2008) refueling outage as a mitigation measure. The remaining seven welds had no recordable indications that exceeded the IWB-3500 acceptance criteria.

The applicant stated that it performed MSIP on RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds. In addition, the applicant stated that post-MSIP phased array UT was performed in accordance with the ASME Code Section XI, 1998 Edition through 2000 Addenda, with acceptable results.

Salem Unit 2. The applicant examined the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds during the first and second ISI 10-year intervals, including volumetric (UT) and surface (PT) examinations. Several of the weld UT examinations documented recordable indications. All of these indications were evaluated against the acceptance criteria of ASME Code Section XI, IWB-3500. All of the indications were acceptable. No indications were documented during the PT examinations.

During the third ISI 10-year interval, the applicant examined the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds by BMV examinations during the fall 2006 refueling outage in accordance with MRP Letter 2004-05. The applicant stated that no evidence of leakage was identified.

The applicant also examined the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds during the fall 2009 refueling outage by phased array UT in accordance with the ASME Code Section XI, 1998 Edition through 2000 Addenda. The RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds had no recordable indications that exceeded the IWB-3500 acceptance criteria.

The applicant performed MSIP only on the RPV outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds. The applicant stated that post-MSIP phased array UT was performed in accordance with the ASME Code Section XI, 1998 Edition through 2000 Addenda, with acceptable results.

Frequency for Future Inspections for the Alloy 82/182 Dissimilar Metal Butt Welds.

Salem Unit 1. For the four reactor vessel inlet and three outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds that are classified as Category “C” in accordance with “Primary System Piping Butt Weld Inspection and Evaluation Guidelines (MRP-139),” Revision 1, the applicant stated that 50 percent of these welds will be volumetrically inspected once during the next 6 years. If no cracks are found during these inspections, the applicant stated that these welds will then be inspected according to the approved ISI program schedule consistent with the existing ASME code examination program or an NRC-approved alternative.

For the Salem Unit 1 RPV No. 14 outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt weld that is Category “G” in accordance with MRP-139, Revision 1, the applicant stated that this weld will be volumetrically inspected twice over the next four refueling outages. If no additional indications or growth are detected after the second examination, the applicant stated that the examination schedule will continue with the existing code examination program for unflawed conditions or an NRC-approved alternative.

Salem Unit 2. For the Salem Unit 2 RPV inlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds that are Category “E” in accordance with MRP-139, Revision 1, the applicant stated that 100 percent of these welds will be volumetrically inspected every 6 years. For the Salem Unit 2 RPV outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds that are Category “C” in accordance with MRP-139, Revision 1, the applicant stated that 50 percent of these welds will be volumetrically inspected once during the next 6 years. If no cracks are found during these inspections, the applicant stated that these welds will then be inspected according to the NRC-approved ISI program schedule consistent with the existing ASME code examination program or an NRC-approved alternative.

For both Salem Units 1 and 2, future examinations of the RPV inlet and outlet nozzle-to-safe-end dissimilar metal Alloy 82/182 butt welds beyond the above schedule for both units will be determined by the Nickel Alloy Aging Management Program (LRA Appendix B, Section B.2.2.6). Implementation of this program is a commitment (Commitment No. 46) in LRA Appendix A, Section A.5.

The staff finds that the applicant has followed the required inspection program in monitoring the structural integrity of the Alloy 82/182 dissimilar metal butt welds and has mitigated some of the dissimilar metal welds with MSIP. The staff was aware of the indication detected in nozzle No. 14 in the Unit 1 outlet nozzle and subsequent MSIP. The applicant submitted for staff information a report on the MSIP (ADAMS Accession No. ML090500386). The staff is incorporating ASME Code Case N-770 into 10 CFR 50.55a in the current rulemaking effort. Once the final rule for updating 10 CFR 50.55a is issued, the applicant will need to follow the inspection requirements of Code Case N-770 and associated conditions in 10 CFR 50.55a to inspect the Alloy 82/182 dissimilar metal butt welds as a part of its CLB.

The RPV No. 14 outlet nozzle-to-safe-end Alloy 82/182 butt weld that contained the PWSCC flaw will be re-examined in the fall 2011 and fall 2014 refueling outages in accordance with MRP-139, Revision 1 requirements. If the examinations show no indication of crack growth or new cracking, the weld will be placed back into the risk informed-inservice inspection (RI-ISI) program for future inspections. RAI 4.4.3-4 is resolved.

In addition to the Alloy 82/182 welds, the staff is also concerned with the structural integrity of the rest of the primary coolant piping. In RAI 4.4.3-5, the staff requested that the applicant discuss, in addition to the LBB evaluation, how the primary coolant loop piping is inspected to ensure its structural integrity during the period of extended operation.

In its response dated February 1, 2010, the applicant stated that a review of the past inspection history, dating back to the beginning of the first ISI 10-year interval for Units 1 and 2, indicates that the welds were examined using PT and UT methods. A review of the surface examination (PT) results found two welds with surface indications that required corrective action. Both of these welds had the indications removed by light surface buffing, and re-examination (PT) found both welds acceptable. These surface indications were not characterized as service-induced flaws.

The UT examination results found some welds with recordable indications. Except for one weld in the Salem Unit 1 RPV No. 14 outlet nozzle-to-safe-end Alloy 82/182 butt weld, these volumetric recordable weld indications were determined to be either geometric indications or acceptable weld flaws that did not exceed the acceptance criteria of the ASME Code Section XI, IWB-3500. The applicant did not find weld indications that required corrective action (i.e., repair or replacement).

The applicant stated that all selected ASME Code Section XI LBB welds are inspected on a periodic basis in accordance with the ASME Code Section XI, 1998 Edition through the 2000 Addenda, and the approved RI-ISI program. Those welds within the LBB scope that contain Alloy 82/182 weld material are also examined in accordance with the requirements of

MRP-139, Revision 1. The applicant stated that these selected weld examinations will continue through the end of the current third ISI 10-year intervals for both Salem Units 1 and 2.

Both Salem units are currently in their third ISI 10-year interval. The Units 1 and 2 primary loop piping that has been approved for LBB is currently subject to inspection in accordance with ASME Code Section XI, 1998 Edition, including the 2000 Addenda; the approved RI-ISI program; and the requirements in MRP-139, Revision 1. These scheduled examinations will continue until the end of the current third ISI 10-year interval. Following completion of the current third ISI 10-year interval, the Salem ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be updated as required by 10 CFR 50.55a, and the examinations will be conducted accordingly, consistent with the CLB. The weld inspection requirements contained in MRP-139, Revision 1 will continue into the next (fourth) ISI 10-year interval for both units until all requirements have been satisfied, and then the welds will be placed back into the approved ISI program and/or RI-ISI program for future inspections.

For Units 1 and 2, future examinations of the primary loop piping stainless steel welds beyond the above schedule for both units will be determined by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (LRA Appendix B, Section B.2.1.1). Implementation of this program is a commitment (Commitment No. 1) in LRA Appendix A, Section A.5.

In addition, aging of the CASS elbows will be managed with the new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program (LRA Appendix B, Section B.2.1.6). Implementation of this program is a commitment (Commitment No. 6) in LRA Appendix A, Section A.5.

Notwithstanding the flaw detected in nozzle No. 14 in the Unit 1 outlet nozzle weld, the staff finds that the inspection results provide reasonable assurance that the structural integrity of the primary coolant piping in both units will be maintained. In addition, the applicant has followed the required inspections under the ASME Code Section XI. For the period of extended operation, the applicant will implement various inspection AMPs (ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS); and Nickel Alloy Aging Management programs) to monitor the structural integrity of the primary coolant piping. RAI 4.4.3-5 is resolved.

In summary, the staff finds that the TLAA and LBB evaluation have adequately addressed the thermal aging embrittlement of the CASS elbows in the primary coolant piping and the transient cycles for the fatigue flaw growth calculation in the LBB evaluation. In addition, the applicant has addressed the potential PWSCC of Alloy 82/182 dissimilar butt welds with mitigation (i.e., MSIP) and enhanced inspections. The applicant has also implemented ASME inspection programs for the primary coolant piping. The staff concludes that the applicant has demonstrated that the LBB-approved primary coolant piping will maintain structural integrity for the period of extended operation

4.4.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA of the LBB analysis for the primary coolant loop piping in LRA Section A.4.4.3. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.7.3.2, the staff concludes that the summary description of the applicant’s actions to address the TLAA for LBB analysis of the subject LBB piping is adequate.

4.4.3.4 Conclusion

On the basis of its review, consistent with SRP-LR Sections 4.7.3.1.1 and 4.7.3.1.3, the staff concludes that the applicant has demonstrated that the LBB analyses for the primary coolant loop piping remain valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i). In addition, pursuant to 10 CFR 54.21(c)(1)(iii), the staff finds that the applicant has demonstrated that the effects of aging on the intended function of the primary coolant loop piping will be adequately managed for the period of extended operation. The UFSAR supplement contains an appropriate summary description of the TLAA evaluation of the subject LBB piping, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.4.4 Applicability of ASME Code Case N-481 to the Salem Units 1 and 2 Reactor Coolant Pump Casings

4.4.4.1 Summary of Technical Information in the Application

LRA Section 4.4.4 discusses applicability of ASME Code Case N-481 to the Salem Units 1 and 2 RCP casings. The applicant stated that periodic volumetric inspections of the welds of the primary loop pump casings of commercial nuclear power plants are required by ASME B&PV Code Section XI and that these inspections require a large amount of time and resources to complete, resulting in large radiation exposure (man-rem). The applicant concluded that the inservice volumetric inspection can be replaced with an acceptable alternate inspection and proposed to use ASME Code Case N-481, "Alternative Examination Requirements for Cast Austenitic Pump Casings," which provides an alternative to the volumetric inspection requirement. The applicant stated that the code case allows the replacement of volumetric examinations of primary loop pump casings with fracture mechanics-based integrity evaluation (item (d) of the code case) supplemented by specific visual examinations. The applicant further stated that Westinghouse demonstrated compliance with ASME Code Case N-481 on a generic basis, which is documented in WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems," and in this evaluation, stress analyses were performed to support fracture mechanics analyses for postulated flaws. The applicant stated that it applied WCAP-13045 to the RCP casings for their 40-year plant life.

The applicant further stated that the TLAA related to ASME Code Case N-481 is thermal aging of CASS and its consequence on fatigue crack growth. The applicant also stated that the 60-year analysis provided a comparison of the Salem pump casing nozzle loadings with the screening loads reported in WCAP-13045: the screening loads in WCAP-13045 bounded the Salem loads anticipated for 60 years of operation; and that the stability of the flaws postulated in the RCP casings has been established by evaluating the necessary material properties against the saturated (fully-aged) fracture toughness values. The applicant concluded that the results of the 60-year analysis show that ASME Code Case N-481 is satisfied for the period of extended operation when supplemented with the visual inspections specified in the code case (items a, b, and c). The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.4.4.2 Staff Evaluation

SRP-LR Section 4 does not list ASME Code Case N-481 analyses for RCP casings as TLAAs that are generic to industry LRAs. As a result, the staff reviewed the TLAA in LRA Section 4.4.4 against the acceptance guidance in SRP-LR Section 4.4.2.1.1 for dispositioning plant-specific

TLAAs in accordance with 10 CFR 54.21(c)(1)(i). The staff also reviewed applicable ASME Code Section XI requirements, the alternative inspection requirements of ASME Code Case N-481, and applicable Westinghouse WCAP reports as part of its review of this TLAA. The staff reviewed LRA Section 4.4.4 to confirm that the analyses remain valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i).

The staff notes that the ASME Code Section XI, up to and inclusive of the 1998 Edition, requires a volumetric inspection of the RCP casing welds and a visual inspection of the pressure boundary components but that the applicant has chosen to perform the visual examinations in ASME Code Case N-481, as supplemented by a plant-specific fracture mechanics assessment, in lieu of performing the required ASME Code Section XI internal visual and volumetric inspections of RCP CASS casings, which is required by ASME Code Section XI, Table IWB-2500-1, Examination Category B-L-1. The staff notes that ASME Code Case N-481 was endorsed for use (without limitations) both in RG 1.147, Revision 12 (May 1999) and Revision 13 (June 2003) and that the applicant performed a plant-specific evaluation (WCAP-14583) to demonstrate safety and serviceability as required by ASME Code Case N-481. The staff reviewed WCAP-14583, which was made available onsite for staff review during the audit. The staff noted that this evaluation is applicable to a 40-year licensed plant life.

The staff notes that, after the issuance of ASME Code Section XI, 2001 Edition, the code did not continue to require volumetric or routine internal visual examinations of RCP casing welds and that the 2001 Edition of the ASME Code Section XI does require the external surface examinations of the pump casing welds to be examined using surface examination techniques and visual examinations of the internal surfaces of the pump casing welds when the RCP is disassembled for other reasons. Since the provision of the code case has been incorporated in the ASME code, the staff annulled ASME Code Case N-481 from RG 1.147 in Revision 15, dated October 2007. LRA Section B.2.1.1 states that the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program plans for the third 10-year inspection interval, approved per 10 CFR 50.55a, are based on the 1998 Edition including 2000 Addenda. Since the applicant's ASME Code Section XI edition of record is the 1998 Edition inclusive of the 2000 Addenda, and since the code case was endorsed for use in RG 1.147, Revisions 12 and 13, the staff finds it acceptable for the applicant to apply ASME Code Case N-481 as an augmentation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for the period of extended operation.

The staff determined that the applicant also performed a plant-specific 60-year analysis for the RCP casing welds to justify the use of the provisions of ASME Code Case N-481 for the period of extended operation and that this analysis is given in Westinghouse Report WCAP-16957-P, dated March 2009.

The staff confirmed that the 60-year analysis in WCAP-16957-P is in the applicant's CLB. The staff also verified that the applicant is using the generic fracture mechanics analysis in WCAP-13045 to determine whether the 60-year plant-specific analysis in WCAP-16957-P remains as a valid basis for inspecting the RCP casings for the period of extended operation in accordance with the alternative outlined in ASME Code Case N-481.

The staff reviewed the analysis in WCAP-16957-P against the generic analysis in WCAP-13045 in order to determine whether the analysis in WCAP-16957-P remains valid for the period of extended operation. The staff notes that, in WCAP-16957-A, the applicant concluded that the Salem design transients and projected design cycles for these transients over a 60-year plant life are bounded by the design transients and design cycles assessed in NRC-approved

WCAP-13045. The staff reviewed the 60-year projected design cycles and compared them to the design cycles used in the generic analysis in WCAP-13045. The staff also compared the loading conditions to confirm that they are bounded by the generic analysis.

Based on this review, the staff finds that the analysis in WCAP-16957-P remains a valid basis for allowing inspection under the ASME Code Case N-481 for the period of extended operation because: (1) the staff has verified that the generic analysis in WCAP-13045 is applicable to Salem's design of the RCP casings; (2) the staff has verified that the plant-specific analysis in WCAP-16957-A is bounded by the generic analysis in WCAP-13045, as approved by the staff; and (3) the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.4.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of the TLAA evaluation of the applicability of ASME Code Case N-481 for the RCP casings in LRA Section A.4.4.4.

On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.4.3.3, the staff concludes that the summary description of the applicant's actions to address the applicability of ASME Code Case N-481 to the RCP casings is adequate.

4.4.4.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.4.3.1.1, the staff concludes that the applicant has demonstrated that the applicability of ASME Code Case N-481 to the RCP casings in the CLB remains valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i). 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), and, therefore, is acceptable.

4.4.5 Salem Unit 1 Volume Control Tank Flaw Growth Analysis

4.4.5.1 Summary of Technical Information in the Application

LRA Section 4.4.5 discusses the Salem Unit 1 volume control tank (VCT) flaw growth analysis. The applicant stated that flaws were identified in the shell to lower head weld of the Salem Unit 1 VCT during 1RF13 (1999). The applicant determined that the flaws found during the inspection were subsurface and not in contact with the environment, therefore, only fatigue would be the contributing mechanism to flaw growth. The analyses concluded that an initial flaw would grow an insignificant amount of only 1.1 x 10^{-5} inches, based on 1,000 pressurization cycles. The applicant also stated that an examination was performed in 1R15 (2002) which found no further flaw growth and that there have been no recordable indications on the Unit 2 VCT.

The applicant stated that the VCT is an operating surge volume tank compensating in part for reactor coolant releases from the RCS as a result of level changes. The applicant further stated that the major pressurization cycles (transients) experienced by the VCT would be inadvertent safety injection events and OBE cycles and, to a lesser extent, plant heatups and cooldowns. In order to determine if the design analyses remain valid for 60 years of operation, the applicant projected the number of cycles for 60 years. LRA Table 4.4.5-1 provides a summary of these pressurization cycles. The applicant concluded that since the total pressurization cycles for 60 years was 312, which is well below the 1,000 pressurization cycles analyzed for the flaw growth analysis, these design analyses remain valid for the period of extended operation. The applicant stated that it established 1,000 pressurization cycles as an arbitrary value for analysis in order to establish a bounding analysis for the operation of the plant. The applicant dispositioned this Salem Unit 1 VCT flaw growth analysis TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.4.5.2 Staff Evaluation

SRP-LR Section 4 does not list VCT flaw growth analyses as TLAAs that are generic to industry LRAs. As a result, the staff reviewed the TLAA in LRA Section 4.4.5 against the acceptance guidance in SRP-LR Section 4.4.2.1.1 for dispositioning plant-specific TLAAs in accordance with 10 CFR 54.21(c)(1)(i), to verify that the analyses remain valid for the period of extended operation.

The staff notes that LRA Section 4.4.5 states that the Salem Unit 1 VCT flaw growth was analyzed for 1,000 pressurization cycles. In LRA Table 4.4.5-1, the applicant projected the number of pressurization cycles as 312 for Salem Unit 1. The staff notes that the applicant provided the 60-year transient projection methodology in LRA Section 4.3.1. The staff reviewed the methodology for plant heatups and cooldowns, inadvertent safety injection events, and OBE cycles and concurs with the 60-year pressurization cycle projections in LRA Table 4.4.5-1. The staff noted that LRA Section 4.4.5 did not identify what methodology was used to perform the flaw growth analyses. Furthermore, in LRA Table 4.3.1-3, the staff noted that one of the upset condition transients is reactor trip from full power, which was not considered in the projected number of pressurization cycles that were used to conclude that the VCT crack growth analyses remained valid during the period of extended operation. By letter dated June 14, 2010, the staff issued RAI 4.4.5-1 requesting that the applicant: (1) clarify which methodology was used to perform the Salem Unit 1 VCT flaw growth analysis and whether the methodology has been approved for use by the NRC, and (2) clarify which NRC document provides the approval of methodology. If the methodology has not been approved by the NRC, justify the methodology for choosing an acceptance criterion of 1,000 pressurization cycles and why the upset condition transient of reactor trip from full power was not considered in the 60-year projection of pressurization cycles that were used to conclude that the VCT crack growth analyses remained valid during the period of extended operation.

In its response dated July 13, 2010, the applicant stated that it submitted the Unit 1 VCT fatigue analysis to the staff by letter dated February 28, 2000 (ADAMS Accession No. ML003691659), and the staff did not provide a specific review and approval of the fatigue analysis. The applicant further stated that the fatigue analysis used the 1989 Edition of ASME Code Section XI analytical technique, specifically, the net section plastic collapse approach in IWB-3640, supplemented by Appendix C of ASME Code Section XI to determine the allowable flaw sizes for the Salem Unit 1 VCT. The applicant provided the basis for using this methodology.

The tank is fabricated from Type 304 stainless steel. The VCT is classified as a Class 2 tank. Currently, there are no flaw evaluation methods for Class 2 components in ASME Code Section XI and, therefore, Class 1 rules in IWB-3600 are generally used for Class 2 components. In IWB-3600, there are also no specific rules for stainless steel tanks.

Due to the inherent ductility and toughness of stainless steels, the net section plastic collapse methodology was used for the failure criteria for stainless steel components. This methodology was chosen to determine the allowable flaw size for the tank. Although there are no specific rules for evaluating stainless steel tanks in IWB-3600, evaluation rules are available for stainless steel piping components in IWB-3640. These are based on the net section plastic collapse approach. ASME Code Section XI, Appendix C provides the net section plastic collapse equations for stainless steel pipes subjected to the primary membrane and bending stresses. These same equations are directly applicable to stainless steel tanks, since they are also cylindrical thin wall components.

The applicant further stated that the methodology described was considered an acceptable method for evaluating the two flaws found in the Unit 1 VCT since the ASME Code Section XI methodology applicable to stainless steel components was used. The applicant also stated that the fatigue analysis submitted to the staff by letter dated February 28, 2000, used an arbitrary value of 1,000 pressurization cycles, in order to establish a bounding analysis for the operation of the plant.

In its response dated July, 13, 2010, the applicant stated that during the TLAA evaluation, the upset condition transient of reactor trip from full power was initially considered, however, during further internal review, it was removed from applicability as a transient condition for the VCT. The applicant stated that the reactor trip from full power transient does not result in a full depressurization of the RCS, because the transient results in RCS pressure lowering to approximately 2,000 pounds per square inch (psi), and then recovering to the normal operating pressure of approximately 2,250 psi with the use of pressurizer heaters and increased charging flow (lower VCT level and pressure). The applicant further stated that since the plant design and the emergency operating procedure prevent the full depressurization of the RCS, there is no pressurization cycling of the VCT during the reactor trip from full power transient. The applicant also explained that safety injection actuation does not occur during a normal reactor trip from full power, since RCS pressure only decreases to approximately 2,000 psi, and the actuation for safety injection occurs at an RCS pressure of approximately 1,780 psi.

The staff reviewed the applicant's response and notes that the applicant submitted the Unit 1 VCT fatigue analysis to the staff by letter dated February 2000, and that the applicant used the methodology of the 1989 Edition of ASME Code Section XI analytical technique, specifically, the net section plastic collapse approach in IWB-3640, supplemented by Appendix C of ASME Code Section XI to determine the allowable flaw sizes for the Salem Unit 1 VCT. The staff finds this methodology acceptable because the VCT is a Class 2 component and since there are no flaw evaluation methods for Class 2 components in ASME Code Section XI, it is acceptable to use Class 1 rules for evaluating stainless steel tanks in IWB-3600, and the evaluation rules can be used for stainless steel piping components in IWB-3640, which are based on the net section plastic collapse approach. The staff also noted that there is no pressurization cycling of the VCT during the reactor trip from full power transient because the pressure only drops from 2,250 psi to approximately 2,000 psi and, therefore, does not see the full depressurization cycle.

Based on its review, the staff finds the applicant's response to RAI 4.4.5-1 acceptable because: (1) the applicant used an acceptable methodology as described above, (2) the crack growth was determined to be very small at 1.1×10^{-5} inches, and (3) reactor trip from full power transient does not provide any pressurization cycling of the VCT. In addition, even if this reactor trip was to be considered, the total pressurization cycles for 60 years would be 712 cycles analyzed for the flaw growth analysis. The staff's concern described in RAI 4.4.5-1 is resolved.

The staff noted that since this analysis is a TLAA, there should be an applicable aging management review (AMR) item that is specific to the aging management of fatigue flaw growth for the Unit 1 VCT. The staff also noted that LRA Table 3.3.2-2, "Chemical and Volume Control System Summary of Aging Management Evaluation," only includes an applicable AMR line item for management of cumulative fatigue damage and does not include an AMR item for fatigue flaw growth for the Unit 1 VCT. By letter dated June 14, 2010, the staff issued RAI 4.4.5-2 requesting that the applicant justify why LRA Table 3.3.2-2 does not include any AMR line items for the Unit 1 VCT in a borated, treated water environment with an aging effect of fatigue flaw growth.

In its response dated July 13, 2010, the applicant stated that by letter dated February 28, 2000, regarding chemical and VCT indication, Salem Unit 1 (ADAMS Accession No. ML003691659), the applicant determined that the root cause for the Unit 1 VCT indication (flaw) was from the welding fabrication process. The applicant further stated that two follow-up ultrasonic examinations of the Unit 1 VCT in 2002 (1RF15) and 2008 (1RF19) found no change in embedded flaw size and that there have been no recordable indications on the Unit 2 VCT. The applicant concluded that since the Unit 1 VCT indications were not considered service-induced or caused by fatigue, the additional aging effect of cracking (e.g., crack growth) due to fatigue or environmental conditions was not included in the LRA. Furthermore, the applicant stated that the normal service temperature of the VCT is less than 60 °C (140 °F) in a treated borated water environment; therefore, LRA Table 3.3.2-2 does not contain a separate line item for the aging effect and mechanism of cracking due to stress-corrosion cracking.

Based on its review, the staff finds the applicant’s response to RAI 4.4.5-2 acceptable because the flaw was identified to be from welding fabrication process, and further UT inspections found no change in the flaw characteristics, such as changes that would occur from fatigue crack growth. The staff’s concern described in RAI 4.4.5-2 is resolved.

The staff notes that the number of 312 pressurization cycles for Unit 1 over the life of the plant as compared to 1,000 cycles is significantly lower and, therefore, is acceptable. The staff also notes that an examination performed in 2002 found no further flaw growth and with the lower number of projected cycles, the staff expects the flaw to grow less than 1.1×10^{-5} inches.

On the basis of its review, consistent with SRP-LR Section 4.4.3.1.1, the staff finds the Salem Unit 1 VCT flaw growth analysis TLAA acceptable because: (1) the methodology used to calculate the flaw growth is an acceptable methodology, (2) the staff has verified that the use of an acceptance criteria of 1,000 cycles is acceptable, and (3) the number of pressurization cycles (312) is significantly lower than the acceptance criteria (1,000 cycles), which demonstrates that the current analysis is bounding and valid for the period of extended operation.

4.4.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of the TLAA evaluation of the Salem Unit 1 VCT flaw growth analysis in LRA Section A.4.4.5. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.4.3.3, the staff concludes that the summary description of the applicant’s actions to address VCT flaw growth analyses is adequate.

4.4.5.4 Conclusion

On the basis of its review of the LRA, consistent with SRP-LR Section 4.4.3.1.1, the staff concludes that the applicant has demonstrated that the Salem Unit 1 VCT flaw growth analysis remains valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i). 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), and, therefore, is acceptable.

4.5 Fuel Transfer Tube Bellows Design Cycles

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 discusses a TLAA related to the fuel transfer tube bellows design cycles. The applicant stated that the fuel transfer tube connects the fuel transfer canal (inside the containment structure) to the transfer pool (inside the fuel handling building). The applicant further stated that the fuel transfer tube passes through the containment wall and through the exterior wall of the fuel handling building.

The applicant stated that the fuel handling building fuel transfer tube is comprised of a 24-inch diameter penetration sleeve penetrating through the containment and fuel handling building walls and three sets of expansion joints (bellows). Each of these three bellows was designed for a minimum of 50 cycles of seismic movement; therefore, this design analysis is a TLAA requiring evaluation for the period of extended operation.

In order to determine if the design analyses will remain valid for 60 years of operation, the applicant conservatively projected the number of seismic cycles for 60 years. The applicant stated that as of January 2009, the Salem transfer tube bellows will have been exposed to zero OBE cycles. The applicant projected that two and three OBEs would occur for Units 1 and 2, respectively, in 60 years of operation. The applicant concluded that since the number of cycles in 60 years is well below the 50 seismic movement cycles analyzed for these bellows, these design analyses remain valid for the period of extended operation. The applicant dispositioned this fuel transfer tube bellows design cycles TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.5.2 Staff Evaluation

SRP-LR Section 4 does not list fuel transfer tube bellows design cycles as TLAAs that are generic to industry LRAs. As a result, the staff reviewed the TLAA in LRA Section 4.5 against the acceptance guidance in SRP-LR Section 4.5.2.1.1 for dispositioning plant-specific TLAAs in accordance with 10 CFR 54.21(c)(1)(i) to verify that the analyses remain valid for the period of extended operation.

LRA Section 4.5 states that the three bellows were designed for a minimum of 50 cycles of seismic movement. The staff notes that the applicant has projected the number of OBE cycles to the end of the period of extended operation as two for Salem Unit 1 and three for Salem Unit 2. The staff concurs with the applicant that the number of cycles of seismic movement will be minimal based on seismological experience of the last 30 years, over which time no seismic movement has occurred, and thus consistent with the applicant’s projected number of OBE cycles. The number of 2 OBE cycles for Unit 1 and 3 OBE cycles for Unit 2 over the life of the plant, as compared to 50 OBE cycles, is significantly lower and, therefore, is acceptable.

Based on its review, consistent with SRP-LR Section 4.5.3.1.1, the staff finds the applicant has demonstrated that the analysis for the fuel transfer tube bellows will maintain their structural integrity for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), because the maximum number of OBE cycles projected for 60 years (e.g., 2 OBE cycles for Unit 1 and 3 OBE cycles for Unit 2) has been demonstrated to be bounded by the 50 OBE cycle limit assumed in the fuel transfer tube bellows design cycles analysis.

4.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of the TLAA evaluation of the fuel transfer tube bellows design cycles in LRA Section A.4.5. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.5.3.2, the staff concludes that the summary description of the applicant's actions to address fuel transfer tube bellows design cycles is adequate.

4.5.4 Conclusion

On the basis of its review of the LRA, consistent with SRP-LR Section 4.5.3.1.1, the staff concludes that the applicant has demonstrated that the fuel transfer tube bellows design cycles analysis remains valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i). 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), and, therefore, is acceptable.

4.6 Crane Load Cycle Limits

4.6.1 Polar Gantry Crane

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6.1 states that the design of the 230/35-ton polar crane in the containment structure complies with the Crane Manufacturers Association of America (CMAA) Specification 70 requirements. The applicant also stated that the polar crane was designed for a minimum of 20,000 load cycles, corresponding to the criteria of CMAA Specification 70 for service Class A. The applicant further stated that the Salem responses for control of heavy loads (NUREG-0612) provided estimates of the expected frequency of lifts for the polar crane. Based on the response to the NUREG-0612 requirements, the estimated number of lifts for the Salem Unit 1 polar crane to date is 900 and is projected to be 1,620 for 60 years. The polar crane was used during original construction, SG replacement, and integrated reactor vessel head replacement, where the estimated number of lifts for these combined major modifications is 100. The applicant also stated that those values apply to Unit 2 as well. Therefore, the applicant stated that the total number of lifts for the Salem Units 1 and 2 polar cranes is estimated to be 1,720 each through the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.6.1.2 Staff Evaluation

SRP-LR Section 4 does not list polar gantry crane cycle limits TLAAs that are generic to industry LRAs. The staff notes that in LRA Section 2.3.3.9, “Scoping and Screening,” the applicant listed a total of 33 cranes and hoists as within the scope of license renewal. In addition, LRA Table 3.3.2-9 requires a TLAA of crane/hoist bridge/trolley girders for aging management due to cumulative fatigue damage/fatigue in accordance with the GALL Report recommendations. However, LRA Section 4.6, “Crane Load Cycle Limit,” includes TLAAs for only three cranes: the polar gantry crane, the fuel handling crane, and the cask handling crane. TLAAs for other in-scope cranes with bridge/trolley girders are not provided in the LRA. Therefore, in RAI 4.6-1 dated July 19, 2010, the staff requested that the applicant explain why TLAAs for other cranes with bridge/trolley girders are not included in the LRA.

In its response dated August 10, 2010, the applicant stated that TLAAs are provided only for those cranes with girders whose analyses were considered to meet all six criteria specified in 10 CFR 54.3(a), therefore, defining them as a TLAA. Of the 33 in-scope cranes and hoists, the polar gantry crane and the cask handling crane have girders with an associated TLAA as discussed in LRA Section 4.6. The third crane discussed in LRA Section 4.6 is the fuel handling crane, which has a girder with an associated TLAA and is evaluated as part of the fuel handling and fuel storage system, and not part of the cranes and hoists system. The design specifications for these three cranes incorporate the requirements of either EOCI-61, “Specification for Electric Overhead Traveling Cranes,” 1961, or its replacement document, CMAA-70, “Specifications for Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes.” Contained within CMAA-70 are a set of design limitations on the allowable stress range for repeated loads that depends upon load cycles, service class, and design configurations. As a result, the polar gantry crane, the fuel handling crane, and the cask handling crane were conservatively considered to have a TLAA and were further evaluated with a service class consisting of a minimum allowable design value of 20,000 load cycles. The remaining

30 in-scope cranes and hoists, including those comprising the fuel handling and fuel storage system, either do not have girders, or have girders that do not have calculations and analyses that would be considered a TLAA.

Based on its review, the staff finds the applicant's response to RAI 4.6-1 acceptable because only the polar gantry crane, the fuel handling crane, and the cask handling crane were designed for cyclical loading. The staff reviewed LRA Section 2.3.39 and UFSAR Section 9.1.4 and found that 24 out of the 33 cranes and hoists listed in LRA Section 2.3.3.9 are monorails without any girders and, therefore, do not require a TLAA. The remaining cranes listed in LRA Section 2.3.3.9, except the polar gantry crane, the fuel handling crane, and the cask handling crane, do not have any design documentation of procurement specifications that indicate that they are required to be designed for cyclical loading. Therefore, the staff's concern described in RAI 4.6-1 is resolved.

The staff reviewed LRA Section 4.6.1 and found that the design of the polar crane complies with the CMAA Specification 70, Class A requirements and is designed for a minimum of 20,000 load cycles.

LRA Section 4.6.1 states that the total number of load cycles for the Salem Unit 1 polar crane during the last 33 years of operation is estimated to be 900. Based on this operating experience data, the applicant stated that the total number of projected load cycles for the Unit 1 polar crane through the period of extended operation is 1,720. The Unit 2 polar crane is also not likely to experience more than 1,720 cycles through the period of extended operation, which is significantly less than the design value of 20,000 cycles. The staff agrees with this statement because there will be approximately 40 refueling outages for an operating period of 60 years and it will require 500 lifts each refueling outage to reach 20,000 lifts. The containment polar crane typically performs less than 40 lifts per outage. Therefore, the polar crane load cycle fatigue analyses for Salem Units 1 and 2 will remain valid during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

4.6.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the load cycle limits of the polar crane to CMAA Specification 70 in LRA Section A.4.6.1. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.6.3.2, the staff concludes that the summary description of the applicant's actions to address crane load cycles is adequate.

4.6.1.4 Conclusion

Based on its review, consistent with SRP-LR Section 4.6.3.1.1.1, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the polar crane load cycle analyses will 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), and, therefore, is acceptable.

4.6.2 Fuel Handling Crane

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.2 states that the design of the 5-ton fuel handling crane in the fuel handling building complies with the CMAA Specification 70 requirements. The applicant also stated that the fuel handling crane was designed for a minimum of 20,000 load cycles, corresponding to the criteria of CMAA Specification 70 for service Class A. The applicant further stated that the total number of lifts to date for Salem Unit 1 is estimated to be 6,600, as stated in the applicant's response to NUREG-0612. Therefore, the applicant stated that the total number of lifts for Salem Unit 1 is estimated to be 12,000 through the period of extended operation and that this number of lift cycles is also representative for the Salem Unit 2 fuel handling crane. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.6.2.2 Staff Evaluation

SRP-LR Section 4 does not list fuel handling crane cycle limits TLAAs that are generic to industry LRAs. The staff reviewed LRA Section 4.6.2 to verify that the load cycle analyses of the fuel handling crane remain valid for the period of extended operation.

The total number of load cycles for the Salem Unit 1 fuel handling crane during the last 33 years of operation is estimated to be 6,600. Based on this operating experience data, the total number of projected load cycles for the Unit 1 fuel handling crane through the period of extended operation is 12,000, which is less than the design value of 20,000 cycles. The staff finds the load cycle analyses acceptable because the staff conservatively estimates that if each of the Units 1 and 2 reactors have a total of 193 fuel assemblies, where one third of the assemblies are normally replaced during each refueling outage, fuel core offloads, and subsequent reloading during every refueling outage over a 60-year period (40 outages), the result would be 15,440 cycles, which is less than the design value of 20,000 cycles. Therefore, the staff finds that the fuel handling crane load cycle fatigue analyses for Salem Units 1 and 2 will remain valid during the period of extended operation and complies with 10 CFR 54.21(c)(1)(i).

4.6.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the load cycle limits for the fuel handling crane in LRA Section A.4.6.2. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address crane load cycles is adequate.

4.6.2.4 Conclusion

Based on its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the fuel handling crane load cycle analyses will 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), and, therefore, is acceptable.

4.6.3 Cask Handling Crane

4.6.3.1 Summary of Technical Information in the Application

LRA Section 4.6.3 states that the existing cask handling cranes were replaced in 2009 by single failure-proof cask handling cranes rated for 115 tons (main hoist) and 10 tons (auxiliary hoist). Each of these cranes was designed in accordance with ASME NOG-1-2004, NUREG-0554, and NUREG-0612 criteria in order to be certified as an NRC-approved single failure-proof design. The applicant also stated that the cask handling cranes were designed to CMAA Specification 70-04 standards for Class A service. CMAA 70 requires that a crane classified as Service Class A shall be designed for a minimum of 20,000 load cycles. The applicant further stated that the projected number of lifts for the cask handling cranes is 1,560 through the period of extended operation. This estimate is based upon the expected number of fuel casks that must be handled through the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

4.6.3.2 Staff Evaluation

SRP-LR Section 4 does not list cask handling crane cycle limits TLAAs that are generic to industry LRAs. The staff reviewed LRA Section 4.6.3 and found that the design of the cask handling cranes complies with the CMAA Specification 70, Class A requirements and are designed for a minimum of 20,000 load cycles. The staff noted that the new cask handling cranes became operational in 2009. The applicant estimated that the total number of lifts by the cask handling cranes through the period of extended operation is 1,560. The staff finds this estimate of 1,560 lifts realistic since the cask handling cranes are not frequently used and are used only to lift the spent fuel casks from the pool to a transporter. The cask handling crane is designed for 20,000 lift cycles, which is significantly more than the 1,560 lifts expected. Because the applicant’s projected number of lifts is significantly less than the design criteria, the staff finds that the cask handling crane load cycle fatigue analyses for Units 1 and 2 will remain valid during the period of extended operation and complies with 10 CFR 54.21(c)(1)(i).

4.6.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of load cycle limits of the Salem Unit 1 and 2 cask handling cranes in LRA Section A.4.6.3. Based on its review of the UFSAR supplement, consistent with SRP-LR Section 4.6.3.2, the staff concludes that the summary description of the applicant’s actions to address crane load cycles is adequate.

4.6.3.4 Conclusion

Based on its review, consistent with SRP-LR Section 4.6.3.1.1.1, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the cask handling crane load cycle analyses will 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), and, therefore, is acceptable.

4.7 Environmental Qualification of Electrical Equipment

4.7.1 Summary of Technical Information in the Application

LRA Section 4.7 summarizes the evaluation of environmental qualification (EQ) of electrical equipment for the period of extended operation. The applicant stated that the Salem EQ program is in compliance with the requirements of 10 CFR 50.49 and is being used to manage the aging of equipment in the EQ program during the current license term. The applicant also stated that the existing Salem EQ program will be used to manage aging of equipment in the EQ program during the period of extended operation and includes provisions to ensure that the qualification bases are maintained and the components do not exceed their qualified lives. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the period of extended operation and the EQ of electric components program will manage the aging effects of the components associated with the EQ TLAA.

4.7.2 Staff Evaluation

The staff evaluated this TLAA consistent with SRP-LR Section 4.4. 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 DBEs. The 10 CFR 50.49 EQ program is a TLAA for purposes of license renewal. The TLAA of the EQ of electrical components includes all long-lived and passive electrical and instrumentation and controls (I&C) components that are important to safety and are located in a harsh environment. The harsh environments of the plant are those areas subject to environmental effects by a loss-of-coolant accident (LOCA), high-energy line break (HELB), or post-LOCA environment. 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. The applicant shall demonstrate one of the following for each type of EQ equipment: (i) the analyses remain valid for the period of extended operation, (ii) the analyses have 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.

The staff reviewed LRA Sections 4.7 and B.3.1.2, plant basis documents, additional information provided to the staff, and interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirements of 10 CFR 54.21(c)(1). The staff reviewed the applicant's EQ program to determine whether it will assure that the electrical and I&C components covered under this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation. Per the GALL Report Section X.E1, plant EQ programs that implement the requirements of 10 CFR 50.49 are viewed as AMPs under license renewal. GALL AMP X.E1, "Environmental Qualification (EQ) of Electric Components," provides a means to meet the requirements of 10 CFR 54.21(c)(1)(iii).

The staff's evaluation of the components qualification focused on how the EQ program manages the aging effects to meet the requirements of 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Section 4.7, Section B.3.1.2, and program basis documents. LRA Section 4.7 discusses the component reanalysis attributes, including analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. On the basis of its audit, the staff finds that the EQ program, which the applicant claimed to be consistent with GALL AMP X.E1, “Environmental Qualification (EQ) of Electric Components,” is indeed consistent with this GALL Report AMP. The staff further concludes that the applicant’s EQ of electrical equipment TLAA is implemented in accordance with 10 CFR 54.21(c)(1)(iii).

The staff finds that the applicant’s EQ program is capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ program provides assurance that the aging effects will be managed and that components within the scope of the EQ program will continue to perform their intended functions for the period of extended operation. Therefore, the staff finds that the applicant’s EQ program demonstrates, pursuant to 10 CFR 54.21(c)(1)(iii), that the effect of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.7.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of EQ of electrical equipment in LRA Section A.4.7. Based on its review of the UFSAR supplement, consistent with SRP-LR Section 4.4.3.3, the staff concludes that the summary description of the applicant’s actions to address EQ of electrical equipment is adequate.

4.7.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.4.3.1.3, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that for the EQ of electrical equipment, the effects of aging of the intended functions 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), and, therefore, is acceptable.

4.8 Conclusion

The staff reviewed the information provided in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concludes that the applicant 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) that the aging effects 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 found that the UFSAR supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes that one plant-specific exemption is in effect that is based on TLAAs and that the applicant has provided an adequate evaluation that justifies the continuation of this exemption for the period of extended operation, as required by 10 CFR 54.21(c)(2).

With regard to these matters, the staff concludes that the activities authorized by the LRA 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 54.21(c), are in accordance with the Atomic Energy Act of 1954 and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The U.S. Nuclear Regulatory Commission (NRC or the staff) issued its safety evaluation report (SER) with open items related to the renewal of the operating license for Salem Nuclear Generating Station, Units 1 and 2, (Salem) on November 4, 2010. On December 1, 2010, the applicant presented its license renewal application (LRA), and the staff presented its review findings to the Advisory Committee on Reactor Safeguards (ACRS) Plant License Renewal Subcommittee. The staff reviewed the applicant's comments on the SER and completed its review of the LRA. The staff's evaluation is documented in an SER that was issued by letter dated March 31, 2011. Subsequently, the staff received additional information from the applicant dated May 18, 2010, that provided clarifications regarding how the effectiveness of the Water Chemistry Program will be verified for the aging management for loss of material and cracking in treated borated water. The staff's review of this information is documented in Sections 3.0.3.1.2, 3.0.3.1.11, 3.2.2.1.2, 3.2.2.1.3, 3.3.2.1.15, and 3.3.2.1.16, respectively, of this SER.

During the 583rd meeting of the ACRS, May 12–14, 2011, the ACRS completed its review of the Salem LRA and the staff's SER. The ACRS documented its findings in a letter to the Commission dated May 26, 2011. A copy of this letter is provided on the following pages of this SER Section.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 – 0001

May 25, 2011

The Honorable Gregory B. Jaczko
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2

During the 583rd meeting of the Advisory Committee on Reactor Safeguards (ACRS), May 12-14, 2011, we completed our review of the license renewal application for the Salem Nuclear Generating Station, Units 1 and 2, and the final Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during its meeting on December 1, 2010. During these reviews, we had the benefit of discussions with representatives of the NRC staff and the applicant, PSEG Nuclear LLC. We also had the benefit of the documents referenced. 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 the applicant to manage age-related degradation provide reasonable assurance that Salem Nuclear Generating Station, Units 1 and 2, can be operated in accordance with their current licensing bases (CLB) for the period of extended operation without undue risk to the health and safety of the public.

2. The application for renewal of the operating licenses of Salem Nuclear Generating Station, Units 1 and 2, should be approved.

BACKGROUND AND DISCUSSION

Salem Nuclear Generating Station contains two Westinghouse pressurized water reactor units with large dry containments. The site is located approximately 40 miles southwest of Philadelphia, Pennsylvania, and approximately 8 miles from Salem, New Jersey. Hope Creek Generating Station is also located at the same site.

Operation of Salem Unit 1 was initially restricted to a licensed power of 3338 MWt until 1986, when the power level was increased to the design power rating of 3411 MWt. The original licensed power rating for Unit 2 was 3411 MWt. The current licensed power of each unit is 3459 MWt, which includes 1.4 percent power uprates that were implemented in 2001. The Salem Unit 1 steam generators were replaced in 1998, and the Unit 2 steam generators were replaced in 2008. The Salem Unit 1 and Unit 2 reactor vessel heads were replaced in 2005.

In August 2009, PSEG Nuclear LLC requested renewal of the Salem operating licenses for 20 years beyond the current license terms, which expire on August 13, 2016, for Unit 1 and April 18, 2020, for Unit 2.

In the final SER, the staff documented its review of the license renewal application and other information submitted by the applicant or obtained during two staff audits and one inspection conducted at the plant site. The staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's aging management programs (AMPs); and the identification and assessment of time-limited aging analyses (TLAAs) requiring review.

The applicant identified the SSCs that fall within the scope of license renewal and performed an aging management review for these SSCs. The applicant will implement 48 AMPs for license renewal. These include 32 existing programs and 16 new programs. A total of 42 AMPs, 10 of which contain enhancements, are consistent with the guidance in the Generic Aging Lessons Learned (GALL) Report. Eight AMPs contain one or more exceptions to approaches specified in the GALL Report. Six plant-specific programs manage issues that are either not addressed or are not consistent with guidance in the GALL Report. These include three existing programs for inspections of buried non-steel piping, periodic inspections and testing of boral neutron-absorbing material in the spent fuel racks, and management of cracking in nickel alloy components in the reactor coolant system. Three new plant-specific programs include periodic inspections of high voltage insulators; periodic inspections of piping, ducts, tanks, and heat exchangers; and periodic inspections of above-ground non-steel tanks. We reviewed the plant-specific programs and the AMP exceptions to the GALL Report, and we agree with the staff that they are acceptable.

The applicant identified the systems and components requiring TLAAs and reevaluated them for the period of extended operation. The staff concluded that the applicant has provided an acceptable list of TLAAs, as defined in 10 CFR 54.3. Furthermore, the staff concluded that in all cases the applicant has met the requirements of the License Renewal Rule by demonstrating that the TLAAs will remain valid for the period of extended operation, or the TLAAs have been projected to the end of the period of extended operation, or the aging effects will be adequately managed for the period of extended operation. We concur with the staff's conclusion that the TLAAs have been properly identified and that the required criteria will be met for the period of extended operation.

The staff conducted two license renewal audits and one inspection at the Salem site. The audits verified the appropriateness of the aging management scoping and screening methodology, and AMP consistency with guidance in the GALL Report. The inspection examined the scoping and screening of SSCs that are not safety related and verified the adequacy of the guidance, documentation, and implementation of selected AMPs. The audit and inspection teams also performed independent searches of the Salem condition report databases to confirm that plant-specific operating experience has been adequately addressed during the AMP development and implementation processes. Based on the audits and inspections, the staff concluded in the final SER that the proposed activities will adequately manage the aging of SSCs identified in the application and that the intended functions of these SSCs will be maintained during the period of extended operation. We agree with these conclusions.

The AMP for Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements will be used to manage the aging effects and mechanisms of non-environmentally qualified, in-scope, inaccessible, medium voltage (i.e., 4.16kV and 13.8kV) cables. No low voltage cables are in-scope for this program. The program is consistent with the guidance in Revision 2 of the GALL Report.

Cable test frequencies will be established based on the test results and industry operating experience. The maximum time between tests will be six years. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established based on inspection results to minimize the exposure of medium voltage cables to significant moisture. The maximum time between inspections will be one year.

Salem Units 1 and 2 have not experienced any cracking of ASME Class 1 small bore piping. The AMP for One-Time Inspection of ASME Code Class 1 Small-Bore Piping includes external visual examinations, two volumetric examinations from a population of 36 susceptible small bore socket welds on Unit 1, and two volumetric examinations from a population of 34 susceptible welds on Unit 2. These commitments are consistent with the guidance in Revision 2 of the GALL Report. We concur with the staff's conclusion that this program, which accounts for the Salem plant-specific operating experience, will adequately monitor and manage the effects of aging in these welds.

Salem Units 1 and 2 do not have any in-scope buried tanks. None of the in-scope buried piping has cathodic protection. Inspections conducted during the existing Buried Piping and Tanks Inspection Program have identified missing protective wrapping on a leaking welded joint in out-of-scope fuel oil piping and missing protective coating for in-scope auxiliary feedwater piping at Unit 1. No similar conditions have been identified during inspections at Unit 2. Although the Unit 1 auxiliary feedwater piping had a reduction in wall thickness, there have been no age-related, through-wall, piping failures in the plant operating experience.

The enhanced Buried Piping and Tanks Inspection Program will contain guidance and methods consistent with current industry initiatives for the management of buried piping integrity. Salem inspection priorities will be derived from a composite corrosion risk ranking process that accounts for the safety significance, corrosion susceptibility, and radioactive fluid content of each in-scope piping system. Prior to the period of extended operation and every 10 years thereafter, the applicant will conduct inspections of excavated buried piping sections:

- A total of four sections of carbon steel piping selected from the auxiliary feedwater, service water, fire protection, circulating water, demineralized water, non-radioactive drains, and compressed air systems

- One section of gray cast iron fire protection piping

- One section of ductile cast iron fire protection piping

- One section of pre-stressed concrete piping selected from the service water and circulating water systems

- One section of stainless steel fuel transfer tube piping

The staff concluded that the proposed program will adequately monitor and manage the aging of buried piping. We agree with this conclusion.
Several instances of corrosion of the Salem Units 1 and 2 containment liners and the presence of borated water leakage in containment have been observed over the past 15 years. During the Salem Unit 2 outage in the fall of 2009, a very small leak of borated water was observed at the fuel transfer canal telltale. Borated water was observed on the containment liner plate moisture barrier under the fuel transfer canal. These leaks were attributed to reactor cavity leakage.

The containment liners are covered with insulation panels to a height of approximately 32 feet above the containment concrete floor. In consideration of industry operating experience with liner corrosion in the area near the floor joint and moisture barrier, the applicant removed the bottom portions of the insulation and inspected the inaccessible area. Liner corrosion was observed in the 3-inch region above the moisture barrier and below the bottom of the lowest leak chase channel. No corrosion was observed in the area below the moisture barrier or above the leak chase channel. The liner corrosion depth was measured, determined to be acceptable, and the liner surface was cleaned and recoated. The Salem Unit 1 and Unit 2 moisture barriers have been repaired or replaced. Prior to the period of extended operation, the applicant will remove 57 additional randomly selected insulation panels on each unit and inspect the condition of the containment liner behind each panel. Every three years during the period of extended operation, one insulation panel will be removed at random in each quadrant, and the liner will be inspected.

In addition, augmented inspections will be performed in the area of the containment liners under the fuel transfer canal and behind the insulation that are subject to possible leaks from the reactor cavity. These inspections will be performed on a frequency of once per Containment Inservice Inspection Period, starting with the current period. These augmented inspections will continue, under the IWE program, as long as leakage from the reactor cavity or fuel transfer canal is observed between the containment liner and the insulation.

The staff has concluded that these sampling and inspection programs will provide adequate monitoring and management of containment liner corrosion in the inaccessible locations. We agree with this conclusion.

Leakage from the Salem Unit 2 spent fuel pool (SFP) is currently approximately one gallon per day, as measured from its telltale drains. Leakage from the Unit 1 SFP is much larger. The measured leakage rate has been stable at approximately 100 gallons per day for the last seven years. The applicant has concluded that the Unit 1 leakage is through numerous small cracks in the welds in the fuel pool liner that are too small to be readily identified, located, and repaired. While no commitments have been made, the applicant indicated that efforts will continue to identify and, if possible, repair fuel pool liner cracks.

Prior to 2003, blockages in the leakage collection system piping allowed water leaking from the SFP to enter seismic construction gaps between the fuel building, auxiliary building, and containment. The escaping water created a tritium plume that extends in the soil southwest from the Unit 1 fuel building and containment, within the site boundary.

In 2003, the applicant implemented a leakage management program to control and capture the leaking water. The program ensures that the fuel pool telltale drains remain open, thus the leakage can be collected in a sump. A drain was also installed in the seismic gap to route water from that pathway into a collection vessel in the auxiliary building. Measurements show that

these actions have reduced flow into the surrounding soils, and tritium levels have trended downward. Remediation work has reduced the tritium concentrations in the plume.
The applicant will continue the Unit 1 fuel pool leakage management programs through the period of extended operation. The chemistry of the water from the drains will be monitored to assess any change that could indicate unexpected degradation of the concrete and rebar. Readings outside the expected range would require further investigation and evaluation.

Exposure to borated water could lead to dissolution of cementitious materials and weakening of the concrete. The water could also potentially corrode and weaken the rebar. However, examination of concrete cores from the Connecticut Yankee SFP and additional laboratory tests performed on concrete specimens for the applicant indicate that the structural capacity will not be significantly affected. The Structures Monitoring Program includes the reinforced concrete trench that collects the borated water drainage from the SFP telltale drains. Monitoring the condition of this trench provides an indication of the degradation in inaccessible areas and helps provide assurance that degradation of inaccessible structures will be detected before a loss of an intended function. The sump room wall will be inspected in accordance with ACI 349.3R every 18 months during the period of extended operation.

The applicant will also take core samples in each of the Unit 1 SFP walls (east and west) that have shown ingress of borated water through the concrete. The rebar exposed during sampling will be examined for signs of corrosion. The staff has concluded that these measures are sufficient to demonstrate that the effects of aging will be adequately managed so that the intended function(s) of the SFP structure will be maintained consistent with the CLB for the period of extended operation. We agree with this conclusion.

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 licenses for Salem Nuclear Generating Station, Units 1 and 2. The programs established and committed to by the applicant provide reasonable assurance that Salem Nuclear Generating Station, Units 1 and 2, can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public. The PSEG Nuclear LLC application for renewal of the operating licenses for Salem Nuclear Generating Station, Units 1 and 2, should be approved.

Sincerely,

/RA/

Said Abdel-Khalik
Chairman

References:

1. U.S. Nuclear Regulatory Commission, NUREG-1944, "Safety Evaluation Report Related to the License Renewal of Salem Nuclear Generating Station," 04/27/2011 (ML111170317)

2. Letter to U.S. Nuclear Regulatory Commission, "Application for Renewed Operating Licenses – Salem Nuclear Generating Station, Unit No. 1 and Unit No. 2," 08/18/2009 (ML092430230)

3. Letter to Thomas Joyce, "Scoping and Screening Audit Summary Regarding the Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application (TAC NOS. ME1834 and ME1836)," 08/25/2010 (ML102280211)

4. Letter to Thomas P. Joyce, "Salem Nuclear Generating Station Units 1 and 2, and Hope Creek Generating Station – NRC License Renewal Inspection Report 05000272/2010010, 05000311/2010010, 05000354/2010010," 10/01/2010 (ML102740350)

5. Letter to Thomas P. Joyce, "Salem Nuclear Generating Station Units 1 and 2, and Hope Creek Generating Station – NRC License Renewal Inspection Report Nos. 05000272/2010006, 05000311/2010006, 05000354/2010006," 10/14/2010 (ML102871030)

6. Letter to Thomas Joyce, "Audit Report Regarding the Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application (TAC NOS. ME1834 and ME1836)," 11/09/2010 (ML102430586)

7. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report With Open Items Related to the License Renewal of Salem Nuclear Generating Station," 11/2010 (ML103120172)

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Salem Nuclear Generating Station, Units 1 and 2 (Salem) in accordance with NRC regulations and NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated September 2005. Title 10, Section 54.29, 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 have been documented in a supplement to NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2,” dated March 30, 2011.

APPENDIX A

SALEM NUCLEAR GENERATING STATION LICENSE RENEWAL COMMITMENTS

During the review of the Salem Nuclear Generating Station (Salem) license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff), PSEG Nuclear, LLC (PSEG 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: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	A.2.1.1	Ongoing	LRA Section B.2.1.1
2	Water Chemistry	A.2.1.2	Ongoing	LRA Section B.2.1.2
3	Reactor Head Closure Studs	A.2.1.3	Ongoing	LRA Section B.2.1.3
4	Boric Acid Corrosion	A.2.1.4	Ongoing	LRA Section B.2.1.4
5	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	A.2.1.5	Ongoing	LRA Section B.2.1.5
6	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) is a new program that will provide for aging management of the thermal embrittlement of CASS piping, piping elements and piping components in a reactor coolant environment. The program will include a screening for components susceptible to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For "potentially susceptible" components, thermal aging embrittlement will be managed through either an enhanced volumetric inspection or a component-specific flaw tolerance evaluation.	A.2.1.6	Program to be implemented prior to the period of extended operation.	LRA Section B.2.1.6
7	PWR Vessel Internals is a new program that will include the following activities: 1. Participate in the industry programs for investigating and managing aging effects on reactor internals. 2. Evaluate and implement the results of the industry programs as applicable to the reactor internals. 3. Upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	A.2.1.7	Program to be implemented prior to the period of extended operation. Inspection plan to be submitted to NRC not less than 24 months prior to the period of extended operation.	LRA Section B.2.1.7

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
8	Flow-Accelerated Corrosion	A.2.1.8	Ongoing	LRA Section B.2.1.8
9	Bolting Integrity Program is an existing program that will be enhanced to include: 1. In the following cases, bolting material should not be reused: a. Galvanized bolts and nuts, b. ASTM A490 bolts; and c. Any bolt and nut tightened by the turn of nut method.	A.2.1.9	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.9
10	Steam Generator Tube Integrity	A.2.1.10	Ongoing	LRA Section B.2.1.10
11	Open-Cycle Cooling Water System	A.2.1.11	Ongoing	LRA Section B.2.1.11
12	Closed-Cycle Cooling Water System is an existing program that will be enhanced to include: 1. The Component Cooling System is not currently analyzed for sulfates, which is not consistent with the EPRI standard. The program will be enhanced to include monitoring this parameter as part of the Closed-Cycle Cooling Water program. 2. The emergency diesel generator jacket water system is not currently analyzed for azole or ammonia, chlorides, fluorides, and microbiologically-influenced corrosion in accordance with the current EPRI standard. The program will be enhanced to include these parameters as part of the Closed-Cycle Cooling Water program. 3. The Closed-Cycle Cooling Water program for the Chilled Water System will have a program or hardware change to bring the system chemistry parameters into compliance with EPRI 1007820, prior to the period of extended operation. 4. New recurring tasks will be established to enhance the performance monitoring of selected heat exchangers cooled by Component Cooling System. 5. New recurring tasks will be established for enhancing the	A.2.1.12	Program to be enhanced and one-time inspections to be implemented prior to the period of extended operation.	LRA Section B.2.1.12

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
	performance monitoring of selected Chilled Water System components. 6. A one-time inspection of selected components will be established for Chilled Water System piping to confirm the effectiveness of the Closed-Cycle Cooling Water program. 7. A one-time inspection of selected closed-cycle cooling water components in stagnant flow areas will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water program. 8. A one-time inspection of selected closed-cycle cooling water chemical mixing tanks and associated piping will be conducted to confirm the effectiveness of the closed cycle cooling water program on the interior surfaces of the tanks and associated piping. 9. The program will be enhanced such that the Heating Water and Heating Steam System will have a pure water control program instituted, in accordance with EPRI 1007820, prior to the period of extended operation. 10. New recurring tasks will be established for enhancing the performance monitoring of selected Heating Water and Heating Steam System components. 11. A one-time inspection of selected Heating Water and Heating Steam System piping will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water program.			
13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to include: 1. Visual inspection of structural components and structural bolts for loss of material due to general, pitting, and crevice corrosion and structural bolting for loss of preload due to self-loosening. 2. Visual inspection of the rails in the rail system for loss of material due to wear.	A.2.1.13	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.13

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
	3. The acceptance criteria will be enhanced to require evaluation of significant loss of material due to corrosion for structural components and structural bolts, and significant loss of material due to wear of rail in the rail system.			
14	Compressed Air Monitoring	A.2.1.14	Ongoing	LRA Section B.2.1.14
15	Fire Protection is an existing program that will be enhanced to include: 1. The routine inspection procedures will be enhanced to provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. 2. The fire pump supply line functional tests will be enhanced to provide specific guidance for examining exposed external surfaces of the fire pump diesel fuel oil supply line for corrosion during pump tests. 3. The Halon and Carbon Dioxide fire suppression system functional test procedures will be enhanced to include visual inspection of system piping and component external surfaces for signs of corrosion or other age related degradation, and for mechanical damage. The system functional test procedures will also be enhanced to include acceptance criteria stating that identified corrosion or mechanical damage will be evaluated with corrective action taken as appropriate.	A.2.1.15	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.15 Salem Letter LR-N10-0225 RAI B.2.1.15-02 July 8, 2010
16	Fire Water System is an existing program that will be enhanced to include: 1. The Fire Water System aging management program will be enhanced to inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter.	A.2.1.16	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in Commitment.	LRA Section B.2.1.16

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
	2. The Fire Water System aging management program will be enhanced to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2002 Edition), Section 5-3.1.1. These inspections will be performed by the 50-year in-service date and every 10-years thereafter.			
17	Aboveground Steel Tanks is an existing program that will be enhanced to include: 1. The program will be enhanced to include UT measurements of the bottom of the tanks that are supported on concrete foundations (Fire Protection Water Storage Tanks). Measured wall thickness will be monitored and trended if significant material loss is detected. These thickness measurements of the tank bottom will be taken and evaluated against design thickness and corrosion allowance to ensure that significant degradation is not occurring and the component intended function would be maintained during the extended period of operation. 2. The program will be enhanced to provide routine visual inspections of the Fire Protection Water Storage Tanks external surfaces. The visual inspection activities will include inspection of the grout or sealant between the tank bottom and the concrete foundation for signs of degradation.	A.2.1.17	Program to be enhanced prior to the period of extended operation. Tank bottom UT inspections will also be performed prior to the period of extended operation.	LRA Section B.2.1.17
18	Fuel Oil Chemistry is an existing program that will be enhanced to include: 1. Equivalent requirements for fuel oil purity and fuel oil testing as described by the Standard Technical Specifications. 2. Analysis for particulate contamination in new and stored fuel oil. 3. Addition of biocides, stabilizers and corrosion inhibitors as determined by fuel oil sampling or inspection activities.	A.2.1.18	Program to be enhanced and one-time inspections to be implemented prior to the period of extended operation.	LRA Section B.2.1.18

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
	4. Quarterly analysis for bacteria in new and stored fuel oil. 5. Internal inspection of 350-gallon Fire Pump Day Tanks (S1DF-1DFE21 and S1DF-1DFE23) using visual inspections and ultrasonic thickness examination of tank bottoms. 6. Sampling of new fuel oil deliveries for API gravity and flash point prior to off load. 7. Internal inspection of the 30,000-gallon Fuel Oil Storage Tanks (S1DF-1DFE1, S1DF-1DFE2, S2DF-2DFE1 and S2DF-2DFE2) using visual inspections and ultrasonic thickness examination of tank bottoms. 8. To confirm the absence of any significant aging effects, a one-time inspection of each of the 550-gallon Diesel Fuel Oil Day Tanks will be performed.			
19	Reactor Vessel Surveillance is an existing program that will be enhanced to include: 1. The Reactor Vessel Surveillance program will be enhanced to state the bounding vessel inlet temperature (cold leg) limits and fluence projections, and to provide instructions for changes. a. Inlet Temperature Range Limitation: 525°F (min) to 590°F (max) b. Fluence Limitation (max.): 1.00×10^{20} n/cm^2 (E > 1.0 MeV) 2. The Reactor Vessel Surveillance program will be enhanced to describe the capsule storage requirements and the need to retain future pulled capsules. 3. The Reactor Vessel Surveillance program will be enhanced to specify a scheduled date for withdrawal of capsules including pulling one of the remaining four capsules during the period of extended operation to monitor the effects of long-term exposure to neutron embrittlement for each Salem Unit. Those dates shall be approved by the NRC prior to withdrawal of the capsules, in accordance with 10 CFR Part 50,	A.2.1.19	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.19

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
	Appendix H. 4. The Reactor Vessel Surveillance program will be enhanced to incorporate the requirements for (1) withdrawing the remaining capsules when the monitor capsule is withdrawn during the period of extended operation and placing them in storage for the purpose of reinstituting the Reactor Vessel Surveillance Program if required, i.e. if the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, and subsequently the basis for the projection to 60 years warrant the reinstitution, and (2) changes to the reactor vessel exposure conditions and the potential need to re-institute a vessel surveillance program will be discussed with the NRC staff prior to changing the plant's licensing basis. 5. Enhancements to the current Reactor Vessel Surveillance program will be made to require that if future plant operations exceed the limitations or bounds specified for cold leg temperatures (vessel inlet) or higher fluence projections, then the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC shall be notified. a. Inlet Temperature Range Limitation: 525°F (min) to 590°F (max) b. Fluence Limitation (max.): 1.00 x 10^{20} n/cm^2 (E > 1.0 MeV)			
20	One-Time Inspection is a new program and will be used for the following: 1. To confirm the effectiveness of the Water Chemistry program to manage the loss of material, cracking, and the reduction of heat transfer aging effects for aluminum, copper alloy, nickel alloy, steel, stainless steel, and cast austenitic stainless steel in treated water, treated borated water where dissolved oxygen may not be controlled to less than 100 ppb, steam, and reactor coolant environments. 2. To confirm the effectiveness of the Fuel Oil Chemistry program to manage the loss of material aging effect for aluminum, copper alloy,	A.2.1.20	Program to be implemented prior to the period of extended operation. One-time inspections to be performed within the ten-year period prior to the period of extended operation.	LRA Section B.2.1.20 Salem Letter LR-N11-0005 RAI B.2.1.20-01 January 6, 2011 Salem Letter LR-N11-0148

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
	gray cast iron, steel and stainless steel in a fuel oil environment. 3. To confirm the effectiveness of the Lubricating Oil Analysis program to manage the loss of material and the reduction of heat transfer aging effects for aluminum, copper alloy, ductile cast iron, gray cast iron, steel, stainless steel, cast austenitic stainless steel and titanium alloy in a lubricating oil environment. The sample plan for inspections associated with the One-Time Inspection program will be developed to ensure there are adequate inspections to address each of the material, environment, and aging effect combinations. A sample size of 20% of the population (up to a maximum of 25 inspections) will be established for each of the sample groups.			May 18, 2011
21	Selective Leaching of Materials is a new program that will include one-time inspections of a representative sample of susceptible components to determine where loss of material due to selective leaching is occurring. A sample size of 20% of susceptible components will be subjected to a one-time inspection with a maximum of 25 inspections for each of the susceptible material groups. Where selective leaching is identified, further aging management activities will be implemented such that the component intended function is maintained consistent with the current licensing basis through the period of extended operation.	A.2.1.21	Program to be implemented prior to the period of extended operation. One-time inspections to be performed within the ten-year period prior to the period of extended operation.	LRA Section B.2.1.21 Salem Letter LR-N10-0324 September 1, 2010 Salem Letter LR-N11-0005 RAI B.2.1.21-01 January 6, 2011
22	Buried Piping Inspection is an existing program that will be enhanced to include: 1. A cathodic protection study will be performed prior to entering the period of extended operation to assess the possibility and benefits of installing a system, versus other mitigative and preventive actions. 2. A soil characterization study will be performed prior to entering the period of extended operation to determine soil corrosivity in the	A.2.1.22	Program to be enhanced prior to the period of extended operation. Inspection Schedule identified in Commitment.	LRA Section B.2.1.22 Salem Letter LR-N10-0322 RAI B.2.1.22 September 7, 2010 Salem Letter

APPENDIX A: SALEM UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
	vicinity of buried piping. The results of the study will be used as an input to the program so that inspections will be performed at the locations of highest risk. 3. At least one (1) opportunistic or focused excavation and inspection will be performed on each of the Fire Protection System material groupings, which include carbon steel, ductile cast iron, and gray cast iron piping and components during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation. 4. The following inspections apply to buried, carbon steel, safety-related portions of the specified systems. A different segment for each system will be inspected in each ten year period. a. At least one (1) opportunistic or focused excavation and inspection on each of the Auxiliary Feedwater and Compressed Air systems during the ten (10) years prior to entering the period of extended operation. b. At least three (3) opportunistic or focused excavations and inspections of the Service Water System during the ten (10) years prior to entering the period of extended operation. c. If, as a result of the soil characterization study, it is determined that the soil is not corrosive in the vicinity of all of the Auxiliary Feedwater, Service Water, and Compressed Air systems, Salem will perform at least (1) opportunistic or focused excavation and inspection on each of the respective systems every ten (10) years during the period of extended operation. d. If, as a result of the soil characterization study, it is determined that the soil is corrosive in the vicinity of the Auxiliary Feedwater, Service Water, or Compressed Air systems, Salem will perform at least two (2) opportunistic or focused excavations and inspections on the respective			LR-N10-0372 RAI B.2.1.22-02 November 10, 2010 Salem Letter LR-N10-0444 RAI B.2.1.22-03 January 18, 2011

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	susceptible system(s) every ten (10) years during the period of extended operation. 5. If, based on the results of the initial soil characterization study, it is determined that the soil is not corrosive in the vicinity of the Auxiliary Feedwater, Service Water, or Compressed Air systems, Salem will perform a second Soil Characterization Study within approximately fifteen (15) years of the original study. The results of the second soil study will be entered into the Corrective Action Program for evaluation. 6. The buried Auxiliary Feedwater System piping located inside the Unit 2 Fuel Transfer Tube Area (approximately 125 feet) will be replaced and rerouted above ground prior to entering the period of extended operation.			

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23	One-Time Inspection of ASME Code Class 1 Small-Bore Piping is a new program that will manage the aging effect of cracking in stainless steel small-bore, less than nominal pipe size (NPS) 4 inches and greater than or equal to NPS 1 Class 1 piping through the use of a combination of volumetric examinations and visual inspections. The One-Time Inspection of ASME Code Class 1 Small Bore-Piping is a new program that will be enhanced to include the following activity: Salem Units 1 and 2 will perform four volumetric examinations, two per unit, from a population of 36 susceptible Class 1 small-bore socket welds on Unit 1 and 34 susceptible Class 1 small-bore socket welds on Unit 2. Provided the technology is available, these inspections shall be performed prior to entering the period of extended operation. More specifically, the volumetric examinations will analyze Class 1 small-bore socket welds as follows: • Two Class 1 small-bore socket welds (one per unit) for intergranular stress corrosion cracking; and • Two Class 1 small-bore socket welds (one per unit) for cracking caused by thermal fatigue (thermal and mechanical loading)	A.2.1.23	Program to be implemented prior to the period of extended operation. One-time inspections to be performed within the ten-year period prior to the period of extended operation. Program to be enhanced prior to the period of extended operation. The inspection schedule will be consistent with the Salem ISI Program requirements.	LRA Section B.2.1.23 Salem Letter LR-N10-0247 RAI B.2.1.23-01 July 8, 2010
24	External Surfaces Monitoring is a new program that directs visual inspections of components such as piping, piping components, ducting and other components in the scope of license renewal, exposed to an air environment, to manage aging effects.	A.2.1.24	Program to be implemented prior to the period of extended operation.	LRA Section B.2.1.24
25	Flux Thimble Tube Inspection is a new program that manages the loss of material due to wear of the flux thimble tube materials using inspection methods such as eddy current testing.	A.2.1.25	Program to be implemented prior to the period of extended operation.	LRA Section B.2.1.25
26	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting	A.2.1.26	Program to be	LRA Section B.2.1.26

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	Components is a new program that manages the aging of the internal surfaces of piping, piping components, piping elements, ducting components, tanks and heat exchanger components.		implemented prior to the period of extended operation.	
27	Lubricating Oil Analysis	A.2.1.27	Ongoing	LRA Section B.2.1.27
28	ASME Section XI, Subsection IWE is an existing program that will be enhanced to include: 1. Inspection of a sample of the inaccessible liner covered by insulation and lagging once prior to the period of extended operation and every 10 years thereafter. Should unacceptable degradation be found additional insulation will be removed as necessary to determine extent of condition in accordance with the corrective action process. Prior to the period of extended operation • The samples shall include 57 randomly selected containment liner insulation panels per unit. • The randomly selected containment liner insulation panels will not include containment liner insulation panels previously removed to allow for inspection. • The examination will be performed by either removing the containment liner insulation panels and performing a visual inspection, or by using a pulsed eddy current (PEC) remote inspection, with the containment liner insulation left in place, to detect evidence of loss of material. If evidence of loss of material is detected using PEC, the containment liner insulation panel will be subsequently removed to allow for visual and UT examinations. • All inspections will be completed by August 2016 for both Salem Units. Approximately one third of the 57 inspections will be	A.2.1.28	Program to be enhanced prior to the period of extended operation. Inspection Schedule identified in Commitment.	LRA Section B.2.1.28 Salem Letter LR-N10-0165 RAI B.2.1.28-1 RAI B.2.1.28-2 May 13, 2010 Salem Letter LR-N10-0244 RAI 3.5.2.2.1.7-01 July 15, 2010 Salem Letter LR-N10-0321 RAI B.2.1.28-04 RAI B.2.1.33-06 September 1, 2010 Salem Letter LR-N10-0382 October 15, 2010

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	completed during each refuel outage (Salem Unit 1 involves the following refuel outages: Spring 2013, Fall 2014, and Spring 2016. Salem Unit 2 involves the following refuel outages: Fall 2012, Spring 2014, and Fall 2015). It is acceptable to perform greater than one third of the inspections in any refuel outage to accelerate the inspection schedule. During the period of extended operation • One containment liner insulation panel will be selected, at random, for removal from each quadrant, during each of the three Periods in an Inspection Interval. Therefore, a total of 12 containment liner insulation panels will be selected, in each unit, during each ten year Inspection Interval, to allow for examination of the containment liner behind the containment liner insulation. • The randomly selected containment liner insulation panels in each quadrant will not include containment liner insulation panels previously selected. 2. Visual inspection of 100% of the moisture barrier, at the junction between the containment concrete floor and the containment liner, will be performed in accordance with ASME Section XI, Subsection IWE program requirements, to the extent practical within the limitation of design, geometry, and materials of construction of the components. The bottom edge of the stainless steel insulation lagging will be trimmed, if necessary, to perform the moisture barrier inspections. This inspection will be performed prior to the period of extended operation, and on a frequency consistent with IWE inspection requirements thereafter. Should unacceptable degradation be found, corrective actions, including extent of condition, will be addressed in accordance with the corrective action process.			

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	As a follow-up to inspections performed during the 2009 refueling outage, the following specific corrective actions will be performed on Unit 2 prior to entry into the period of extended operation: • Examine the accessible ¾” knuckle plate. If corrosion is observed to extend below the surface of the moisture barrier, excavate the moisture barrier to sound metal below the floor level and perform examinations as required by IWE. • Perform remote visual inspections, of the six capped vertical leak chase channels, below the containment floor to determine extent of condition. • Remove the concrete floor and expose the ¼” containment liner plate (floor) for a minimum of two of the vertical leak chase channels with holes. Perform examination of exposed ¼” containment liner plate (floor) as required by IWE. Additional excavations will be performed, if necessary, depending upon conditions found at the first two channels. • Remove ½” containment liner insulation panels, adjacent to accessible areas where there are indications of corrosion, to determine the extent of condition of the existing corroded areas of the containment liner plate. • Perform augmented examinations of the areas of the ½” containment liner plate behind insulation panels, where loss of material was previously identified, in accordance with IWE-2420. • Examine 100% of the moisture barrier in accordance with IWE-2310 and replace or repair the moisture barrier to meet the acceptance standard in IWE-3510. As a follow-up to inspections performed during the 2010 refueling			

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	outage, the following specific corrective actions will be performed on Unit 1 prior to entry into the period of extended operation: • Perform augmented examinations of the ¾” containment liner (knuckle plate) at 78’ elevation in accordance with IWE-2420. • Perform augmented examinations of the areas of the ½” containment liner plate behind insulation panels, where loss of material was previously identified, in accordance with IWE-2420. • Remove ½” containment liner insulation panels, adjacent to accessible areas where there are indications of corrosion, to determine the extent of condition of the existing corroded areas of the containment liner plate. 3. ASME Section XI, Subsection IWE program scope will be revised to include the following welds that are currently exempted from Subsection IWE and governed under ASME Section XI, Subsection IWB or IWC. The scope of the revision will include the cap plate to penetrating pipe pressure boundary welds, for penetrating pipe constructed of stainless steel for those penetrations with a normal operating temperature greater than 140 degrees F. 4. Owner augmented inspections will be performed at the Salem Unit 1 and Unit 2 area of the Containment liner, under the fuel transfer canal and behind the Containment liner insulation, which are subjected to leaks from the reactor cavity. These owner augmented inspections will be performed on a frequency of once per Containment Inservice Inspection Period, starting with the current Period. These owner augmented inspections will continue, under the IWE program, as long as leakage from the reactor cavity or fuel transfer canal is observed between the Containment liner and the Containment liner insulation, including during the PEO.			

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29	ASME Section XI, Subsection IWL, is an existing program that will be enhanced to include: 1. Examination and acceptance criteria in accordance with the guidance contained in ACI 349.3R.	A.2.1.29	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.29 Salem Letter LR-N10-0165 RAI B.2.1.29-1 May 13, 2010
30	ASME Section XI, Subsection IWF	A.2.1.30	Ongoing	LRA Section B.2.1.30
31	10 CFR Part 50, Appendix J	A.2.1.31	Ongoing	LRA Section B.2.1.31
32	Masonry Wall is an existing program that will be enhanced to include: 1. Additional buildings and masonry walls as described in A.2.1.32. 2. Add an Examination Checklist for masonry wall inspection requirements. 3. Specify an inspection frequency of not greater than 5 years for masonry walls.	A.2.1.32	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.32
33	Structures Monitoring is an existing program that will be enhanced to include: 1. Additional structures and components as described in A.2.1.33. 2. Concrete structures will be observed for a reduction in equipment anchor capacity due to local concrete degradation. This will be accomplished by visual inspection of concrete surfaces around anchors for cracking and spalling. 3. Clarify that inspections are performed for loss of material due to corrosion and pitting of additional steel components, such as embedments, panels and enclosures, doors, siding, metal deck, and anchors. 4. Require inspection of penetration seals, structural seals, and elastomers, for degradations that will lead to a loss of sealing by visual inspection of the seal for hardening, shrinkage and loss of	A.2.1.33	Program to be enhanced prior to the period of extended operation. Core sample Inspection schedule identified in commitment.	LRA Section B.2.1.33 Salem Letter LR-N10-0165 RAI B.2.1.33-1 RAI B.2.1.33-2 May 13, 2010 Salem Letter LR-N10-0321 RAI B.2.1.33-05 September 1, 2010 Salem Letter

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	strength. 5. Require the following actions related to the spent fuel pool liner: a. Perform periodic structural examination of the Fuel Handling Building per ACI 349.3R to ensure structural condition is in agreement with the analysis. b. Monitor telltale leakage and inspect the leak chase system to ensure no blockage. c. Test water drained from the telltales and seismic gap for boron, chloride, iron, and sulfate concentrations; and pH. Acceptance criteria will assess any degradation from the borated water. Sample readings outside the acceptance criteria will be entered into and evaluated in the corrective action program. d. Perform one shallow core sample in each of the Unit 1 Spent Fuel Pool walls (east and west) that have shown ingress of borated water through the concrete. The core samples will be examined for degradation from borated water. Also the core samples (east and west walls) will expose rebar, which will be examined for signs of corrosion. The core sample from the west wall will be taken by the end of 2013 and the core sample from the east wall will be taken by the end of 2015. e. Perform a structural examination per ACI 349.3R every 18 months of the Unit 1 Spent Fuel Pool wall in the sump room where previous inspections have shown ingress of borated water through the concrete. 6. Require monitoring of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF. 7. Add an Examination Checklist for masonry wall inspection requirements. 8. Parameters monitored for wooden components will be enhanced to include: Change in Material Properties, Loss of Material due to Insect Damage and Moisture Damage.			LRN-N10-0414 RAI B.2.1.33-07 December 14, 2010 Salem letter LR-N11-0041 RAI B.2.1.33-07 Update February 25, 2011

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	9. Specify an inspection frequency of not greater than 5 years for structures including submerged portions of the service water intake structure. 10. Require individuals responsible for inspections and assessments for structures to have a B.S. Engineering degree and/or Professional Engineer license, and a minimum of four years experience working on building structures. 11. Perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of 5 years. Groundwater samples in the areas adjacent to Unit 1 containment structure and Unit 1 auxiliary building will also be tested for boron concentration. 12. Require supplemental inspections of the affected in scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes). 13. Perform a chemical analysis of ground or surface water in-leakage when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel. 14. Implementing procedures will be enhanced to include additional acceptance criteria details specified in ACI 349.3R-96. 15. When the reactor cavity is flooded up, Salem will periodically monitor the telltales associated with the reactor cavity and refueling canal for leakage. If telltale leakage is observed, then the pH of the leakage will be measured to ensure that concrete reinforcement steel is not experiencing a corrosive environment. In addition, Salem will periodically inspect the leak chase system associated with the reactor cavity and refueling canal to ensure the telltales are free of significant blockage. Salem will also inspect concrete surfaces for degradation where leakage has been observed, in accordance with this Program.			

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34	RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants is an existing program that will be enhanced to include: 1. Parameters monitored for wooden components will be enhanced to include change in material properties and loss of material due to insect damage and moisture damage. 2. Parameters monitored for elastomers will be enhanced to include hardening, shrinkage and loss of strength due to weathering and elastomer degradation. 3. The inspection requirement for submerged concrete structural components will be enhanced to require that inspections be performed by dewatering a pump bay or by a diver if the pump bay is not dewatered. 4. Specify an inspection frequency of not greater than 5 years for structures including submerged portions of the Service Water Intake Structure. 5. Require supplemental inspections of the in scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes).	A.2.1.34	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.34
35	Protective Coating Monitoring and Maintenance Program	A.2.1.35	Ongoing	LRA Section B.2.1.35

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36	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program and will be used to manage aging of non-EQ cables and connections during the period of extended operation.	A.2.1.36	Program and initial inspections to be implemented prior to the period of extended operation.	LRA Section B.2.1.36
37	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is a new program that will be implemented to manage the aging of the cable and connection insulation of the in scope portions of the Radiation Monitoring System and the Reactor Protection System (i.e., the nuclear instrumentation system).	A.2.1.37	Program and initial assessment of testing and calibration results to be implemented prior to the period of extended operation.	LRA Section B.2.1.37
38	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope inaccessible medium voltage cables (4,160V, 13,800V). The cable test frequency will be established based on test results and industry operating experience. The maximum time between tests will be no longer than 6 years. Manholes and cable vaults associated with the cables included in this aging management program will be inspected for water collection (with water removal as necessary) with the objective of minimizing the exposure of medium voltage cables to significant moisture. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established based on inspection results to minimize the exposure of medium voltage cables to significant moisture. The maximum time between inspections will be no longer than one year.	A.2.1.38	Enhanced program, initial cable tests, and initial manhole and cable vault inspections to be implemented prior to the period of extended operation. Test and inspection schedule identified in commitment.	LRA Section B.2.1.38 Salem Letter LR-N10-0225 RAI B.2.1.38-01 July 8, 2010 Salem Letter LR-N10-0348 LRA Supplement October 7, 2010

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	The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced as follows: 1. Change cable testing maximum frequency from 10 years to 6 years. Change manhole and cable vault inspection maximum frequency from 2 years to 1 year.			
39	Metal Enclosed Bus is a new program that will manage the aging of in-scope metal enclosed busses.	A.2.1.39	Program and initial inspections to be implemented prior to the period of extended operation.	LRA Section B.2.1.39
40	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to confirm the slow progression or the absence of an aging effect with respect to electrical cable connection stressors. A representative sample of non-EQ electrical cable connections will be selected, for one-time testing considering application (medium and low voltage), circuit loading (high loading) and location, with respect to connection stressors.	A.2.1.40	Program and one-time testing to be implemented prior to the period of extended operation.	LRA Section B.2.1.40
41	High Voltage Insulators is a new program that manages the degradation of insulator quality due to the presence of salt deposits or surface contamination.	A.2.2.1	Program to be implemented prior to the period of extended operation.	LRA Section B.2.2.1
42	Periodic Inspection is a new program that manages the aging of piping, piping components, piping elements, ducting components, tanks and heat exchanger components.	A.2.2.2	Program to be implemented prior to the period of extended operation.	LRA Section B.2.2.2
43	Aboveground Non-Steel Tanks is a new program that will manage loss of material of outdoor non-steel tanks. The Aboveground Non-Steel Tanks program will include a UT wall thickness inspection of the bottom of the tanks.	A.2.2.3	Program to be implemented prior to the period of	LRA Section B.2.2.3

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	The UT measurements will be taken to ensure that significant degradation is not occurring and that the component intended function will be maintained during the extended period of operation.		extended operation. Tank bottom UT inspections will also be performed prior to the period of extended operation.	
44	Buried Non-Steel Piping Inspection is an existing program that will be enhanced to include: 1. At least one (1) opportunistic or focused excavation and inspection will be performed on buried reinforced concrete piping and components during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation. 2. At least one (1) opportunistic or focused excavation and inspection will be performed on buried stainless steel penetration bellows between the Containment Structure and the Fuel Handling Building, including the penetration sleeves, during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation. 3. Guidance for inspection of concrete aging effects.	A.2.2.4	Program to be enhanced prior to the period of extended operation. Inspection Schedule identified in Commitment	LRA Section B.2.2.4 Salem Letter LR-N10-0322 RAI B.2.1.22 September 7, 2010
45	Boral Monitoring is an existing program that will be enhanced to include: 1. The program will be enhanced to perform a neutron attenuation measurement on one each of the three (no vent holes, one vent holes and two vent holes) flat plate sandwich Boral test coupons during the first three two-year inspection frequency periods and every six years thereafter for the Exxon spent fuel storage rack assemblies. 2. The program will be enhanced to include acceptance criteria of the neutron attenuation measurement on the Boral test coupons for the Exxon spent fuel storage rack assemblies: A decrease of no more	A.2.2.5	Program to be enhanced prior to the period of extended operation. Inspection Schedule identified in Commitment.	LRA Section B.2.2.5

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	than 5% in Boron-10 content as determined by neutron attenuation measurements. The benchmark Boron-10 content used for comparison will be based on the nominal B-10 areal density in the design basis specification.			
46	Nickel Alloy Aging Management	A.2.2.6	Ongoing	LRA Section B.2.2.6
47	Metal Fatigue of the Reactor Coolant Pressure Boundary is an existing program that will be enhanced to include: 1. Adding transients beyond those defined in the Technical Specifications and the UFSAR, and expanding the fatigue monitoring program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring. 2. Using a software program to automatically count transients and calculate cumulative usage on select components. 3. Addressing the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant identified in NUREG/CR-6260. 4. Requiring a review of additional reactor coolant pressure boundary locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit.	A.3.1.1	Program to be enhanced prior to the period of extended operation.	LRA Section B.3.1.1
48	Environmental Qualification of Electric Components (EQ)	A.3.1.2	Ongoing	LRA Section B.3.1.2
49	Revised Pressure-Temperature (P-T) limits will be submitted to the NRC when necessary to comply with 10 CFR 50 Appendix G.	A.4.2.4	Ongoing	LRA Section 4.2.4
50	Steam Generator Divider Plate Inspection Salem will perform an inspection of each of the four (4) Unit 1 steam generators to assess the condition of the divider plate assembly. The examination technique(s) used will be capable of detecting primary water stress corrosion cracking (PWSCC) in the steam generator divider plate	Not Applicable	Prior to August 2026	Salem Letter LR-N10-0369 RAI 3.1.1-02 October 7, 2010

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	assemblies and the associated welds. The steam generator divider plate inspections will be completed within the first ten (10) years of the Salem Unit 1 period of extended operation.			
51	Steam Generator Tube-to-Tubesheet Weld Cracking Salem will develop a plan for each Unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds. Each plan will consist of two options: <u>Salem Unit 1</u> Option 1 (Analysis): Salem Unit 1 will obtain permanent approval for Alternate Repair Criteria from the NRC, **or** Option 2 (inspection): Salem Unit 1 will perform a One-Time inspection of a representative number of tube-to-tubesheet welds in each of the four (4) steam generators to determine if PWSCC is present. If weld cracking is identified, a) the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b) a periodic monitoring program will be established to perform routine tube-to-tubesheet inspections for the remaining life of the steam generators. <u>Salem Unit 2</u> Option 1 (Analysis):	Not Applicable	Develop a plan prior to the Period of Extended Operation for each Unit. If the analysis option is chosen, implement the requirements of the plan, including obtaining any required NRC approval, by April 2018 for Unit 1, and by April 2028 for Unit 2. If steam generator inspections are to be performed, they will be performed between April 2018 and April 2023 for Unit 1, and April 2028 and April 2033 for Unit 2.	Salem Letter LR-N10-0421 RAI 3.1.1-03 December 1, 2010 Salem Letter LR-N10-0438 Revised Response to RAI 3.1.1-03 December 15, 2010

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	Salem Unit 2 will perform an analytical evaluation either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary of the tubes, where the steam generator tube-to-tubesheet welds are not required for the reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC, **or** Option 2 (inspection): Salem Unit 2 will perform a One-Time inspection of a representative number of tube-to-tubesheet welds in each of the four (4) steam generators to determine if PWSCC is present. If weld cracking is identified, a) the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b) a periodic monitoring program will be established to perform routine tube-to-tubesheet inspections for the remaining life of the steam generators.			
52	Salem will perform a review of design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 based locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Salem plant configuration. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. If any of the limiting locations consist of nickel alloy, NUREG/CR-6909 methodology for nickel alloy will be used in the evaluation	Not Applicable	Prior to the period of extended operation.	Salem Letter LR-N10-0445 RAI 4.3-08 December 21, 2010
53	Salem Fatigue Calculations using WESTEMS™ program Salem will include written explanation and justification of any user intervention in future evaluations using the WESTEMS “Design CUF” (NB-3200 module).	A.4.3.7	Within 60 days of issuance of the renewed operating license	Salem Letter LR-N11-0042 January 31, 2011 Salem Letter LR-N11-0057

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				February 24, 2011
54	Salem Fatigue Calculations using WESTEMS™ program Salem will not use or implement the NB-3600 option (module) of the WESTEMS™ program in future online fatigue monitoring and design calculations.	A.4.3.7	Within 60 days of issuance of the renewed operating license	Salem Letter LR-N11-0042 January 31, 2011 Salem Letter LR-N11-0057 February 24, 2011

APPENDIX B

CHRONOLOGY

This Appendix contains a chronological listing of the routine correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) and PSEG Nuclear, LLC (PSEG or the applicant), and other correspondence regarding the staff's reviews of the Salem Nuclear Generating Station (Salem), Docket Numbers 50-272 and 50-311, license renewal application (LRA).

August 18, 2009	Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application, Volume 1 of 3. (Accession No. ML092430231)
August 18, 2009	Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application, Volume 2 of 3. (Accession No. ML092400531)
August 18, 2009	Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application, Volume 3 of 3. (Accession No. ML092400532)
August 18, 2009	Letter from C.J. Fricker, PSEG Nuclear, LLC: Salem Nuclear Generating Station, Units 1 and 2, Transmittal of License Renewal Application. (Accession No. ML092430230)
August 18, 2009	PSEG Nuclear, LLC, License Renewal Drawing LR-205203, Sheet 1, Main, Reheat and Turbine By-Pass Steam. (Accession No. ML102600447)
August 18, 2009	PSEG Nuclear, LLC, License Renewal Drawing LR-205246, Sheet 1, Demineralized Water - Restricted Areas. (Accession No. ML102600455)
August 18, 2009	PSEG Nuclear, LLC, License Renewal Drawing LR-205246, Sheet 2, Demineralized Water - Restricted Areas. (Accession No. ML102600457)
August 27, 2009	Logistics Trip Report to Delaware Emergency Management Agency Regarding Salem-Hope Creek License Renewal. (Accession No. ML092360621)
August 31, 2009	Letter to T.P. Joyce, PSEG Nuclear, LLC: Receipt and Availability of the License Renewal Application for the Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML092150702)
August 31, 2009	Notice of Receipt and Availability of the License Renewal Application for the Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML092150718)
September 1, 2009	Press Release-09-144: NRC Announces Availability of License Renewal Applications for Salem and Hope Creek Nuclear Power Plants. (Accession No. ML092440653)

September 3, 2009	Comment of W.R. Dunn on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092460442)
September 4, 2009	Comment of F. Alberer on Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092470039)
September 7, 2009	Comment of S.J. Goodman on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092660174)
September 7, 2009	Comment (2) of S.J. Goodman Opposing on License Renewal for the Salem Nuclear Generating Station and Hope Creek Generating Station. (Accession No. ML102280556)
September 8, 2009	Comment of F. Berryhill on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092650382)
September 23, 2009	Comment of R. Panella on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092660447)
October 8, 2009	Letter from C.M. Dolphin, State of New Jersey, Department of Environmental Protection: New Jersey Coastal Zone Management Consultation Response for Salem License Renewal. (Accession No. ML101970075)
October 15, 2009	Letter to T.P. Joyce, PSEG Nuclear, LLC: Notice of Intent to Prepare an Environmental Impact Statement and Conduct the Scoping Process for License Renewal for the Salem Nuclear Generating Station, Units 1 and 2, and the Hope Creek Generating Station. (Accession No. ML092740412)
October 23, 2009	Notice of Meeting on November 5, 2009, to Discuss License Renewal Process and Environmental Scoping for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station, License Renewal Application Review. (Accession No. ML092870635)
October 24, 2009	Comment of D.O. Rickards on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML100570265)
November 3, 2009	Comment (5) of Ellen B. Pompper, on Behalf of Self, Supporting PSEG Nuclear's License Renewal for Salem Nuclear Generating Station and Hope Creek Generating Stations. (Accession No. ML102280559)
November 5, 2009	Transcript of the Salem and Hope Creek License Renewal Public Meeting, November 5, 2009, Pages 1–79. (Accession No. ML093240195)
November 5, 2009	Transcript of the Salem and Hope Creek License Renewal Process, Public Meeting: Evening Session November 5, 2009, Pages 1–63. (Accession No. ML100471177)

November 5, 2009	Comment (6) of Fred Stine, on Behalf of the Delaware Riverkeeper Network, on PSEG Nuclear's License Renewal for Salem Nuclear Generating Station. (Accession No. ML102280560)
November 12, 2009	Letter to J. Douglas, Delaware Tribe of Indians: Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Nuclear Generating Station, Unit 1, License Renewal Applications. (Accession No. ML093090124)
November 19, 2009	Summary of Telephone Conference Call Held on November 12, 2009, Between the NRC and PSEG Nuclear, LLC, Concerning Draft Request for Additional Information Pertaining to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML093160577)
November 24, 2009	Letter to J. Cutler, Deputy State Historic Preservation Officer (SHPO), Pennsylvania Bureau for Historic Preservation; J.R. Little, Director and SHPO, Maryland Historical Trust; D. Saunders, Deputy SHPO, New Jersey Historic Preservation Office; and T.A. Slavin, SHPO, Delaware Division of Historical and Cultural Affairs: Salem Nuclear Generating Station and Hope Creek Generation Station License Renewal Applications Review. (Accession No. ML093160444)
December 22, 2009	Letter from T.A. Slavin, State of Delaware Historical and Cultural Affairs: Delaware SHPO Finding of No Adverse Impact Consultation Response for the Salem and Hope Creek License Renewal. (Accession No. ML101970071)
December 23, 2009	Letter to A.E. Scherer, U.S. Fish and Wildlife Service: Request for List of Protected Species and Water Usage Impacts Within the Area Under Evaluation for the Salem and Hope Creek Nuclear Generating Stations License Renewal Application Review. (Accession No. ML093350019)
December 23, 2009	Letter to P.A. Kurkul, National Marine Fisheries Service: Request for List of Protected Species Within the Area Under Evaluation for the Salem and Hope Creek Nuclear Generating Stations License Renewal Application Review. (Accession No. ML093500057)
February 1, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to Request for Additional Information Regarding Scoping of Metal Fatigue for Salem Nuclear Generating Station, Units 1 and 2, dated January 5, 2010. (Accession No. ML100341330)
February 11, 2010	Letter from M.A. Colligan, National Marine Fisheries Service: NMFS Consultation Response for the Salem and Hope Creek License Renewal Project. (Accession No. ML101970073)
February 23, 2010	Letter from S.W. Gorski, National Marine Fisheries Service: NMFS Habitat Conservation Division Consultation Response for the Salem and Hope Creek License Renewal Project. (Accession No. ML101970072)

February 25, 2010	Letter from J.J. Keenan, PSEG Nuclear, LLC: Salem, Units 1 and 2, Information to Support NRC Staff Review of the License Renewal Boundary Drawings Associated with the Application for Renewed Operating Licenses. (Accession No. ML100680289)
March 22, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information Regarding Section 2.4, Scoping and Screening Results: Structures, for the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML100630203)
March 22, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information Related to Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Section 4.2, "Reactor Vessel Neutron Embrittlement"; Section 4.4.1, "Reactor Vessel Underclad Cracking Analyses"; and Section 4.4.2, "Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses." (Accession No. ML100630161)
April 6, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Project Manager Change for the License Renewal of Salem Nuclear Generating Station, Units 1 and 2 (TAC Nos. ME1834 and ME1836). (Accession No. ML100850459)
April 6, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Corrections to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application Environmental Report. (Accession No. ML100980030)
April 12, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information Regarding Severe Accident Mitigation Alternatives for Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML100910252)
April 14, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information Regarding Balance of Plant Scoping and Screening Results for Salem Nuclear Generating Station, Units 1 and 2 (TAC Nos. ME1834 and ME1836). (Accession No. ML100760661)
April 15, 2010	Request for Additional Information Regarding ASME Section XI, Subsection IWE for the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1836 and ME1834). (Accession No. ML101030025)
April 15, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to Request for Additional Information Related to Section 2.4 of the License Renewal Application. (Accession No. ML101110169)
April 15, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Salem, Units 1 and 2, Submittal of Correction to the License Renewal Application. (Accession No. ML101110170)
April 16, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the License Renewal Application for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station. (Accession No. ML100910367)

April 19, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated March 22, 2010, Related to Section 2.3.3.12 of the License Renewal Application. (Accession No. ML101120674)
April 20, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated March 22, 2010, Related to Section 4 of the License Renewal Application. (Accession No. ML101121088)
April 29, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application. (Accession No. ML101440272)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Post Audit Information, Question # GEN-4. (Accession No. ML101440273)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Cultural Resources. (Accession No. ML101440276)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology. (Accession No. ML101440278)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Chapter 7: Marsh Restoration Project, Fish Assemblage Structure. (Accession No. ML101440279)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Question # ECO-7. (Accession No. ML101440280)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix E. (Accession No. ML101440281)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix E, Attachment E-2. (Accession No. ML101440283)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix F. (Accession No. ML101440285)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix F, Attachment 5. (Accession No. ML101440286)

April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Land Use and Socioeconomics. (Accession No. ML101440287)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Threatened and Endangered Species. (Accession No. ML101440288)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Water/Groundwater. (Accession No. ML101440289)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Waste. (Accession No. ML101440292)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Air. (Accession No. ML101440293)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Alternatives. (Accession No. ML101440294)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Fact Sheet for a Draft NJPDES Permit. (Accession No. ML101440297)
April 30, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information Regarding Scoping and Screening Methodology for the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1836 and ME1834). (Accession No. ML101020481)
May 12, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information Related to Section 2.3, Balance of Plant Scoping and Screening Results, of the License Renewal Application. (Accession No. ML101340565)
May 13, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 15, 2010, Related to Structures and Structures-Related Aging Management Programs for the License Renewal Application. (Accession No. ML101390184)
May 14, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information Related to Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program. (Accession No. ML100630260)
May 20, 2010	Division of License Renewal's Transition from Paper Distribution to Electronic Distribution of Outgoing Correspondence. (Accession No. ML101310138)

May 24, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Generating Station, Units 1 and 2 License Renewal Application, Section 3.3.2 (TAC Nos. ME1836 and ME1834). (Accession No. ML101380511)
May 28, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 30, 2010, Regarding Scoping and Screening Methodology for the License Renewal Application. (Accession No. ML101550259)
June 3, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated May 14, 2010, Related to Aging Management Program B.2.11.6, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel, Associated with the License Renewal Application. (Accession No. ML101610092)
June 7, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Section 3.5 (TAC Nos. ME1834 and ME1836). (Accession No. ML101460061)
June 10, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application Identified During the Audit (TAC Nos. ME1836 and ME1834). (Accession No. ML101440081)
June 10, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1832 and ME1836). (Accession No. ML101460077)
June 11, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML101481009)
June 11, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Sections 3.1.2 and 3.3.2 (TAC Nos. ME1834 and ME1836). (Accession No. ML101550471)
June 14, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Sections 4.3 and 4.4 (TAC Nos. ME1834 and ME1836). (Accession No. ML101480189)
June 14, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated May 24, 2010, Related to Section 3.3.2 of the License Renewal Application. (Accession No. ML101690140)
June 17, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML101390537)

June 25, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML101620190)
June 29, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Subsection 3.1.2.2.14 (TAC Nos. ME1834 and ME1836). (Accession No. ML101680402)
June 29, 2010	Letter from R. Popowski, U.S. Fish and Wildlife Service: Fish and Wildlife Consultation Response for the Salem and Hope Creek License Renewal Project. (Accession No. ML101970077)
June 30, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Section B.3.1.1 (TAC Nos. ME1834 and ME1836). (Accession No. ML101480726)
July 8, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Requests for Additional Information, dated June 10, 2010, June 11, 2010, and June 11, 2010, Related to the License Renewal Application. (Accession No. ML101930533)
July 8, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 7, 2010, Related to Section 3.5 of the License Renewal Application. (Accession No. ML101930534)
July 8, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 10, 2010, Related to the Aging Management Program Audit Associated with the License Renewal Application. (Accession No. ML101940157)
July 12, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application Regarding ASME Section XI ISI, Subsections IWB, IWC, and IWD (TAC Nos. ME1834 and ME 1836). (Accession No. ML101720364)
July 13, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 14, 2010, Related to Sections 4.3 and 4.4 of the License Renewal Application. (Accession No. ML101970042)
July 15, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 17, 2010, Related to Various Sections of the License Renewal Application. (Accession No. ML102010074)
July 19, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Section 4.6 (TAC Nos. ME1834 and ME1836). (Accession No. ML101950487)

July 21, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 25, 2010, Associated with Section 3.3.2 of the License Renewal Application. (Accession No. ML102070561)
July 23, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML101960634)
July 28, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Responses to NRC Request for Additional Information, Related to the Steam Generator Tube Integrity Program and the Metal Fatigue of Reactor Coolant Pressure Boundary Program of the License Renewal Application. (Accession No. ML102140313)
July 30, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML101930496)
August 3, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, ASME Section XI, Subsection IWE (TAC Nos. ME1834 and ME1836). (Accession No. ML101950479)
August 3, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Bolting Integrity (TAC Nos. ME1834 and ME1836). (Accession No. ML101970474)
August 3, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Salem Nuclear Generating Station, Units 1 and 2, 10 CFR 54.21(b) Annual Amendment to License Renewal Application. (Accession No. ML102180171)
August 6, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Buried Piping Inspection Program (TAC Nos. ME1834 and ME1836). (Accession No. ML101540242)
August 9, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML102000404)
August 10, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Responses to NRC Requests for Additional Information, dated July 12, 2010, July 19, 2010, and July 23, 2010, Related to Various Sections of the License Renewal Application. (Accession No. ML102250421)

August 13, 2010	Summary of Telephone Conference Call Held on July 29, 2010, Between the NRC and PSEG Nuclear, LLC, Concerning Follow-Up Questions Pertaining to the Salem Nuclear Generating Station, Units 1 and 2 and Hope Creek Generating Station License Renewal Environmental Review. (Accession No. ML102220012)
August 18, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Supplement to RAI responses submitted in PSEG letter LR-N10-0164, dated May 24, 2010, Related to the Severe Accident Mitigation Alternatives (SAMA) Review of the Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML102320211)
August 18, 2010	Summary of Telephone Conference Call Held on August 4, 2010, Between the NRC and PSEG Nuclear, LLC, Concerning Draft Requests for Additional Information Pertaining to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML102230512)
August 19, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML102030417)
August 25, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Scoping and Screening Audit Summary Regarding the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML102280211)
August 26, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Supplement to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML102440675)
August 26, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Responses to Requests for Additional Information, dated August 3, 2010, Related to Bolting Integrity and, dated July 30, 2010, to SGs and Question Posed During Region 1 Inspection Associated with the License Renewal Application. (Accession No. ML102440676)
September 1, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to Request for Additional Information Related to the ASME Section XI, Subsection IWE Program and Structures Associated with the License Renewal Application. (Accession No. ML102500102)
September 1, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Supplement to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application Related to the Selective Leaching of Materials Aging Management Program. (Accession No. ML102500103)
September 2, 2010	Letter to C. Fricker, PSEG Nuclear, LLC: Revised Review Schedule Regarding the Applications from PSEG Nuclear, LLC for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station (TAC Nos. ME1835, ME1833, and ME1831). (Accession No. ML102360221)

September 3, 2010	Summary of Telephone Conference Call Held on August 16, 2010, Between the NRC and PSEG Nuclear, LLC, Concerning Draft Request for Additional Information Pertaining to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML102320057)
September 7, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to Request for Additional Information, dated August 6, 2010, Related to the Buried Piping Inspection Program Associated with the License Renewal Application. (Accession No. ML102560064)
September 7, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated August 9, 2010, Related to CASS Materials and Response to NRC Request for Additional Information, dated August 19, 2010, Pertaining to CASS Safety Injection Valves, Both Associated with the License Renewal Application. (Accession No. ML102560065)
September 29, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application (TAC Nos. ME1834 and ME1836). (Accession No. ML102460078)
September 29, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Environmental Project Manager Change for the License Renewal of Salem Nuclear Generating Sation, Units 1 and 2 (TAC Nos. ME1835 and ME1833). (Accession No. ML102600308)
October 1, 2010	Salem Nuclear Generating Sation Units 1 and 2, and Hope Creek Generating Station - NRC License Renewal Inspection Report 05000272/2010010, 05000311/2010010, 05000354/2010010. (Accession No. ML102740350)
October 7, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated September 29, 2010, Related to Potential Impact of Primary Water Stress Corrosion Cracking (PWSCC) in Steam Generator (SG) Divider Plate Assembly on Adjacent Components Associated with the License Renewal Application. (Accession No. ML102880063)
October 7, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Supplement to the Salem Nuclear Generating Station License Renewal Application to Revise Maximum Cable Testing and Cable Vault Inspection Frequencies in the Inaccessible Medium-Voltage Cables. (Accession No. ML102880064)
October 8, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Supplement to the Salem Nuclear Generating Station License Renewal Application to Provide Additional Information Related to Steam Generator Aging Management Activities. (Accession No. ML102880065)

October 12, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application, Buried Piping Inspection Program (TAC Nos. ME1834 and ME1836). (Accession No. ML102600340)
October 14, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: IR 05000272-10-006, 05000311-10-006, 05000354-10-006 on June 7–10, 2010, June 21–24, 2010, and August 9–12, 2010, for Salem Nuclear Generating Station, Units 1 and 2 and Hope Creek Generating Station License Renewal Inspection Report - Errata. (Accession No. ML102871030)
October 14, 2010	Summary of Telephone Conference Call Held on September 9, 2010, Between the NRC and PSEG Nuclear, LLC, Concerning Questions Pertaining to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML102640061)
October 14, 2010	Summary of Telephone Conference Call Held on August 18, 2010, Between the NRC and PSEG Nuclear, LLC, Concerning Questions Pertaining to the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application. (Accession No. ML102460095)
October 15, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Supplement to License Renewal Application to Modify the Commitment Regarding the Inspection of the Containment Liner behind the Containment Liner Insulation Panels. (Accession No. ML102940038)
October 15, 2010	Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from PSEG Nuclear, LLC, for Renewal of the Operating License for Salem Nuclear Generating Station. (Accession No. ML092780118)
October 21, 2010	Letter to C. Fricker, PSEG Nuclear, LLC: Issuance of the Environmental Scoping Summary Report for the Staff's Review of the License Renewal Application for Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML102350315)
October 21, 2010	Federal Register Notice: Notice of Availability of the Draft Supplement 45 to the Generic Environmental Impact Statement for the License Renewal of the Hope Creek Generating Station and the Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML102780678)
October 21, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Notice of Availability of Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the Hope Creek Generating Station and the Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML102790646)

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APPENDIX C

PRINCIPAL CONTRIBUTORS

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 contains a listing of the references used in the preparation of the safety evaluation report (SER) prepared during the review of the license renewal application (LRA) for Salem Nuclear Generating Station, Units 1 and 2 (Salem), Docket Numbers 50-272 and 50-311.

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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.)*

Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

Samuel Cuadrado de Jesús, NRC Project Manager

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Salem Nuclear Generating Station, Units 1 and 2, (Salem) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated August 18, 2009, PSEG Nuclear, LLC (PSEG or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the Code of Federal Regulations, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." PSEG requests renewal of the operating licenses (Facility Operating License Numbers DPR-70 and DPR-75) for a period of 20 years beyond the current expiration at midnight August 13, 2016, for Unit 1, and at midnight on April 18, 2020, for Unit 2.

Salem is located approximately 40 miles from Philadelphia, PA, and 8 miles from Salem, NJ. The NRC issued the construction permits for Unit 1 and Unit 2 on August 25, 1968. The NRC issued the operating license for Unit 1 on December 1, 1976, and for Unit 2 on May 20, 1981. Both units are pressurized water reactors that were designed and supplied by Westinghouse. License Amendment Nos. 243 (Salem Unit 1) and 224 (Salem Unit 2), dated May 25, 2001, authorized a 1.4 percent increase in the licensed rated power level of each unit to 3,459 megawatt thermal (MWt).

This SER presents the status of the staff's review of information submitted through May 18, 2011, the cutoff date for consideration in this SER. The staff has resolved all issues associated with requests for additional information and closed all open items since publishing the SER with Open Items. The staff did not identify any new open items that must be resolved before any final determination can be made on the LRA.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

Salem Nuclear Generating Station
PSEG, Nucler LLC
Exelon
License Renewal
Nuclear Power Plant
Docket Numbers 50-272 and 50-311
Aging Management
Scoping and Screening
Time-Limited Aging Analyses

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June 2011