Safety Evaluation Report

Related to the License Renewal of Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2

Docket Nos. 50-454, 50-455, 50-456, and 50-457

Exelon Generation Company, LLC

United States Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

July 2015

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, (BBS) license renewal application (LRA) by the United States (U.S.) Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated May 29, 2013, Exelon Generation Company, LLC (Exelon or the applicant), submitted the LRA in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Exelon requests renewal of the BBS operating licenses (Operating License Nos. NPF-37, NPF-66, NPF-72, and NPF-77, respectively) for a period of 20 years beyond the current expiration at midnight October 31, 2024; November 6, 2026; October 17, 2026; and December 18, 2027, respectively.

Byron is located in north central Illinois, near the town of Byron, Illinois, and near the Rock River approximately 95 miles from Chicago, Illinois. The Braidwood Station is located in northeastern Illinois, near the town of Braidwood, Illinois, and near the Kankakee River approximately 60 miles from Chicago, Illinois. The NRC issued the Byron construction permit on December 31, 1975, and operating licenses on February 14, 1985 (Unit 1), and January 30, 1987 (Unit 2). The NRC issued the Braidwood construction permit on December 31, 1975, and operating licenses on July 2, 1987 (Unit 1), and May 20, 1988 (Unit 2). Each BBS unit has a Westinghouse Electric Corporation (Westinghouse) four-loop pressurized water reactor (PWR) and a turbine-generator furnished by Westinghouse. For both stations, Babcock & Wilcox supplied the steam generators for Unit 1, and Westinghouse supplied the steam generators for Unit 2. Sargent & Lundy was the architect-engineer for both stations. Each containment is a PWR dry ambient containment structure. The BBS licensed power outputs are about 3,645 megawatts thermal with a gross electrical output of approximately 1,260 megawatts electric.

Unless otherwise indicated, this SER presents the status of the staff's review of information submitted through April 17, 2015, the cutoff date for consideration in the SER. The two open items previously identified in the SER with Open Items, issued October 30, 2014, have been closed (see Section 1.5); therefore, no open items remain to be resolved before the final determination is reached by the staff on the LRA.

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ABBREVIATIONS & GLOSSARY TERMS

°F/hr	degree(s) Fahrenheit per hour
μm/yr	micrometer(s) per year
A/LAI	Applicant/Licensee Action Item
AA	all aluminum
AAC	alternate AC
AC	alternating current
ACAR	aluminum conductor aluminum alloy reinforced
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductor steel reinforced
ADAMS	Agencywide Documents Access and Management System
AERM	aging effect requiring management
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
AMP	aging management program
AMR	aging management review
AOO	anticipated operational occurrence
applicant	Exelon Generation Company, LLC
ART	adjusted reference temperature
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient(s) without scram
AWWA	American Water Works Association
B&PV	Boiler and Pressure Vessel
B&W	Babcock & Wilcox
BBS	Byron and Braidwood Stations
BMI	bottom-mounted instrumentation
Braidwood	Braidwood Station, Units 1 and 2
BWR	boiling-water reactor
Byron	Byron Station, Units 1 and 2
CAF	containment access facility
CAP	corrective action program
CASS	cast austenitic stainless steel
CCA	common cause analysis/analyses
CE	Combustion Engineering
CFR	*Code of Federal Regulations*
CLB	current licensing basis/bases
CLSM	controlled low strength material
cm^3	cubic centimeter(s)
CMTR	certified material test report
CO_2	carbon dioxide
CPVC	chlorinated polyvinyl chloride
CRDM	control rod drive mechanism
CRGT	control rod guide tube

CSS	containment spray system
CST	condensate storage tank
cSt	centistoke(s)
CUF	cumulative usage factor
CUF_{en}	environmentally adjusted cumulative usage factor
CVCS	chemical and volume control system
DBA	design-basis accident
DBE	design-basis event
DG	diesel generator
DO	dissolved oxygen
dpa	displacements per atom
E	energy
EAF	environmentally assisted fatigue
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFPY	effective full-power year(s)
EPDM	ethylene propylene diene monomer
EPR	ethylene propylene rubber
EPRI	Electric Power Research Institute
EQ	environmental qualification
EQP	Environmental Qualification Program
ESF	engineered safety feature
ETA	ethanolamine
Exelon	Exelon Generation Company, LLC
FASA	Focused Area Self-Assessment
F_{en}	environmental fatigue life correction factor
FMECA	failure modes, effects, and criticality assessment
FR	*Federal Register*
FSAR	final safety analysis report
ft	foot/feet
GALL	Generic Aging Lessons Learned
GDC	general design criterion/criteria
GEIS	Generic Environmental Impact Statement
GL	generic letter
gpm	gallon(s) per minute
HAZ	heat affected zone(s)
HDPE	high-density polyethylene
HELB	high-energy line break
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control(s)
I&E	inspection and evaluation
IASCC	irradiation-assisted stress-corrosion cracking
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking

ILRT	integrated leak rate test
IN	information notice
in.	inch(es)
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
ISG	interim staff guidance
ISI	inservice inspection
ksi	kilogram(s) per square inch
kV	kilovolt(s)
LAS	low-alloy steel
LBB	leak-before-break
LCO	limiting condition(s) for operation
LER	Licensee Event Report
LLRT	local leakage rate test
LOCA	loss-of-coolant accident
long-lived	not subject to periodic replacement based on a qualified life or specified time period
LR-ISG	license renewal interim staff guidance
LRA	license renewal application
LTOP	low temperature overpressure protection
LWR	light-water reactor
MC	metal containment
MEB	metal-enclosed bus
MEQ	mechanical environmental qualification
MeV	megaelectron volt
MIC	microbiologically influenced corrosion
MoS_2	molybdenum disulfide
MPA	methoxypropylamine
mpy	mil per year
MRP	Materials Reliability Program
MRV	minimum required prestressing force or value
MSIP®	Mechanical Stress Improvement Process
MSIV	main steam isolation valve
MSLB	main steamline break
MUR	measurement uncertainty recapture
n/cm^2	neutrons per square centimeter
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSSS	nuclear steam supply system

OBE	operating basis earthquake
ODSCC	outer-diameter/outside-diameter stress-corrosion cracking
OE	operating experience
OI	open item
OPEX	[Exelon] Operating Experience
OSG	original steam generator
P-T	pressure-temperature
P&ID	piping and instrumentation diagram
passive	without moving parts or a change in configuration or properties
Pb	lead
PEO	period(s) of extended operation
pH	potential of hydrogen
PLL	predicted lower limit
ppm	part(s) per million
PSARV	pressurizer safety and relief valve
psid	pound(s) per square inch differential
PTFE	polytetrafluoroethylene
PTLR	pressure-temperature limits report
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PVCO	oriented polyvinyl chloride
PVDF	polyvinylidene fluoride
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
PWST	primary water storage tank
QA	quality assurance
RAI	request for additional information
RCCA	rod cluster control assembly
RCFC	reactor containment fan cooling
RCL	reactor coolant loop
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCSC	Research Council on Structural Connections
RG	regulatory guide
RHR	residual heat removal
RI-ISI	risk-informed inservice inspection
RIS	Regulatory Issue Summary
RPV	reactor pressure vessel
RSG	replacement steam generator
Rule	10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
RVI	reactor vessel internal
RVLIS	reactor vessel level instrumentation system
RWST	refueling water storage tank
SAT	system auxiliary transformer
SBO	station blackout

SC	structure and component
SCC	stress-corrosion cracking
scoping	within the scope of license renewal
screening	subject to an AMR
SER	safety evaluation report
SFP	spent fuel pool
SIS	safety injection system
SR/IR	source range/intermediate range
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SS	stainless steel
SSC	system, structure, and/or component
staff	U.S. NRC staff
SWOL	structural weld overlay
SX	[essential] service water
SXCT	essential service water cooling tower
TAC	Technical Assignment Control
TF	tendon force
TLAA	time-limited aging analysis
TMI	Three Mile Island
TOC	total organic carbon
TR	technical report
TS	technical specification
U.S.	United States
UFSAR	updated final safety analysis report
UHS	ultimate heat sink
USE	upper-shelf energy
UT	ultrasonic testing
UV	ultraviolet
V	volt(s)
Vac	volt(s) alternating current
VT	Visual Testing (method, e.g., VT-1)
WCAP	Westinghouse Commercial Atomic Power
Westinghouse	Westinghouse Electric Corporation
WOG	Westinghouse Owners Group
XLPE	cross-linked polyethylene

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, (BBS) as filed by Exelon Generation Company, LLC (Exelon or the applicant). By letter dated May 29, 2013, Exelon Generation Company, LLC, submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the BBS 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 John Daily. Mr. Daily may be contacted by telephone at 301-415-3873 or by email at John.Daily@NRC.gov. Alternatively, written correspondence may be sent to the following address:

U.S. Nuclear Regulatory Commission
Division of License Renewal
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Washington, DC 20555-0001

In its May 29, 2013, submission letter, the applicant requested renewal of Operating Licenses NPF-37 and NPF-66 (for Byron, Units 1 and 2, respectively), and NPF-72 and NPF-77 (for Braidwood, Units 1 and 2, respectively), which were issued under Section 103 of the Atomic Energy Act of 1954, as amended, for BBS for a period of 20 years beyond the current expiration dates of midnight October 31, 2024 (Byron Unit 1), November 6, 2026 (Byron Unit 2), October 17, 2026 (Braidwood Unit 1), and December 18, 2027 (Braidwood Unit 2).

Byron is located approximately 95 miles northwest of Chicago, Illinois, and Braidwood is located approximately 60 miles southwest of Chicago, Illinois. The NRC issued the Byron construction permit on December 31, 1975, and operating licenses on February 14, 1985 (Unit 1), and January 30, 1987 (Unit 2). The NRC issued the Braidwood construction permit on December 31, 1975, and operating licenses on July 2, 1987 (Unit 1), and May 20, 1988 (Unit 2). Each Byron and Braidwood unit has a Westinghouse Electric Corporation (Westinghouse) four-loop pressurized-water reactor (PWR) and a turbine-generator furnished by Westinghouse. For both stations, Babcock & Wilcox supplied the steam generators for Unit 1, and Westinghouse supplied the steam generators for Unit 2. Sargent & Lundy was the architect-engineer for both stations. The containment for each unit is a PWR dry ambient containment structure. The Byron and Braidwood licensed power outputs are about 3,645 megawatts thermal with a gross electrical output of approximately 1,260 megawatts electric. The updated final safety analysis report (UFSAR) contains details on the plants and each site.

The license renewal process consists of two concurrent reviews, a technical review of safety and environmental issues. The NRC regulations in 10 CFR Part 54 and 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory

Functions," respectively, set forth requirements for these reviews. The safety review for the Byron and Braidwood license renewal is based on the applicant's LRA and responses to the staff's requests for additional information (RAIs). The applicant supplemented the LRA and provided clarifications through its responses to the staff's RAIs during audits, in meetings, and in docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through April 17, 2015. The staff reviewed information received after this date depending on the stage of the safety review and the volume and complexity of the information.

The public may view the LRA and all pertinent information and materials, including the UFSAR, at the NRC Public Document Room located on the first floor of One White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738 (301-415-4737/800-397-4209); and at the Byron Public Library located at 100 S. Washington Street, Byron, IL 61010; and Fossil Ridge Public Library located at 386 W. Kennedy Road, Braidwood, IL 60408. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC website at http://www.nrc.gov.

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

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

SER Appendix A is a table showing the applicant's commitments related to the renewal of the operating licenses. SER Appendix B is a chronology of the principal correspondence between the staff and the applicant regarding the review of the LRA. 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 is preparing plant-specific supplements to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." Issued separately from this SER, these supplements will discuss the environmental considerations for the license renewals of Byron Station and Braidwood Station.

1.2 License Renewal Background

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

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

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

Concurrent with these initiatives, the staff pursued a separate rulemaking effort (61 FR 28467, June 5, 1996) and amended 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal in order to fulfill NRC responsibilities under the National Environmental Policy Act (NEPA) of 1969. In June 2013, the staff revised and updated the environmental protection regulations (10 CFR 51) and issued a revised GEIS (GEIS, Revision 1) to incorporate lessons learned and knowledge gained from previous plant-specific environmental reviews. The revisions identify 78 environmental impact issues for consideration in license renewal environmental reviews, 59 of which have been determined to be generic to all plant sites.

1.2.1 Safety Review

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

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

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

In implementing these two principles, 10 CFR 54.4, "Scope," defines the scope of license renewal as including those SSCs that: (1) are safety-related, (2) whose failure could affect safety-related functions, or (3) are relied on to demonstrate compliance with the NRC regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transient without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

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

In accordance with 10 CFR 54.21(d), the LRA is required to include a final safety analysis report (FSAR) supplement with a summary description of the applicant's programs and activities for managing aging effects and an evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

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

In 2005, the 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," issued in June 2005. NEI 95-10 details an acceptable method of implementing 10 CFR Part 54. The staff also used the SRP-LR to review the LRA.

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

1.2.2 Environmental Review

Part 51 of 10 CFR contains NRC's environmental protection regulations, which implement Section 102(2) of NEPA. Renewal of a nuclear power plant operating license requires the preparation of an environmental impact statement.

To support the preparation of these environmental impact statements, the staff issued the GEIS, NUREG-1437, in 1996. The staff prepared the GEIS to document its evaluation of potential environmental impacts associated with nuclear power plant license renewals. For certain types of environmental impacts, the GEIS contains generic findings (i.e., Category 1 issues) that apply to all nuclear power plants and are codified in Table B-1 of Appendix B, "Environmental Effect of Renewing the Operating License of a Nuclear Power Plant," to Subpart A, "National Environmental Policy Act - Regulations Implementing Section 102(2)," of 10 CFR Part 51. In accordance with 10 CFR 51.53(c)(3)(i), an LRA may incorporate these generic findings in its environmental report but need not analyze them. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues). The staff documents its environmental review of the generic and plant-specific issues in separate supplemental environmental impact statements to the GEIS.

In June 2013, the staff revised and updated the environmental protection regulations (10 CFR 51) (78 FR 37282, June 20, 2013) and issued a revised GEIS (GEIS, Revision 1) (78 FR 37325, June 20, 2013) to incorporate lessons learned and knowledge gained from previous plant-specific environmental reviews. The revisions identify 78 environmental impact issues for consideration in license renewal environmental reviews, 59 of which have been determined to be generic to all plant sites.

In accordance with NEPA and 10 CFR Part 51, the staff reviewed the plant-specific environmental impacts of license renewal, including whether there was new and significant information not considered in the GEIS. As part of its environmental scoping process, the staff held public meetings for Byron on August 20, 2013, at the Byron Forest Park Reserve District and for Braidwood on August 21, 2013, at the Fossil Ridge Library to obtain public input on plant-specific environmental issues. The plant-specific GEIS supplements will document the results of the environmental reviews with respect to the potential environmental impacts of the proposed action (license renewal) and alternatives for each station.

The staff issued the draft GEIS supplement for Byron on December 24, 2014, and issued the draft GEIS supplement for Braidwood on March 18, 2015. The staff will hold additional public meetings to discuss these draft GEIS supplements for Byron and for Braidwood. Details on these meetings are available on the Byron-Braidwood license renewal public website: http://www.nrc.gov/reactors/operating/licensing/renewal/applications/byron-braidwood.html. The staff plans to publish final plant-specific GEIS supplements separately from these drafts, after considering comments on the drafts.

1.3 Principal Review Matters

Part 54 of 10 CFR describes the requirements for renewal of 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, "Standards for Issuance of a Renewed License," of 10 CFR sets forth the license renewal standards. This SER describes the results of the staff's safety review.

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

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

> 10 CFR 54.19(b) requires that 'each applicant 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 (Agreement No. B-97 for Byron Station, Units 1 and 2, and Agreement No. B-102 for Braidwood Station, Unit 1 and 2) each 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, as amended, lists license numbers NPF-37 (Byron, Unit 1), NPF-66 (Byron, Unit 2), NPF-72 (Braidwood, Unit 1), and NPF-77 (Braidwood, Unit 2).

The applicant requested that conforming changes be made to the Indemnity Agreements, as amended, and the Attachments to said agreements, as required, to ensure that the Indemnity Agreements continue to apply during both the terms of the current licenses and the terms of the renewed licenses. Based on the current language contained in the Indemnity Agreements as cited above, the staff finds that no changes are necessary for this purpose since the current license numbers are retained.

In accordance with 10 CFR 54.21, "Contents of Application – Technical Information," the staff requires that the LRA contain: (a) an integrated plant assessment, (b) a description of any CLB changes during the staff's review of the LRA, (c) an evaluation of TLAAs, and (d) an FSAR 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 (or contains information required by) the 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 to the facility that affect the contents of the LRA, including the FSAR supplement. By letters dated May 5, 2014, and April 6, 2015, the applicant submitted LRA updates which summarized the CLB changes that have occurred during the staff's review of the LRA. These submissions satisfy 10 CFR 54.21(b) requirements.

In accordance with 10 CFR 54.22, "Contents of Application - Technical Specifications," the staff requires that the LRA include changes or additions to the technical specifications (TSs) that are necessary to manage aging effects during the period of extended operation. In LRA Appendix D, the applicant stated that it had not identified any TS changes necessary for issuance of the renewed Byron and Braidwood operating licenses. This statement adequately addresses the 10 CFR 54.22 requirement.

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

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

1.4 Interim Staff Guidance

License renewal is a living program. The staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned help the staff work toward its performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. Interim staff guidance (ISG) is documented for use by the staff, industry, and other interested stakeholders on approaches acceptable to the staff until incorporated into such license renewal guidance documents as the SRP-LR and the GALL Report.

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

Table 1.4-1 Current Interim Staff Guidance

ISG Issue (Approved ISG Number)	Purpose	SER Section
Aging Management of Stainless Steel Structures and Components in Treated Borated Water, Revision 1 (LR-ISG-2011-01)	This LR-ISG provides guidance as to an acceptable approach for managing the effects of aging during the period of extended operation for stainless steel structures and components exposed to treated borated water within the scope of 10 CFR Part 54.	SER Section 3.2.2.1.2
Aging Management Program for Steam Generators (LR-ISG-2011-02)	This LR-ISG evaluates the suitability of using Revision 3 of NEI 97-06 for implementing the steam generator AMP.	The issues in this ISG are addressed in SER Section 3.0.3.2.5.
Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, “Buried and Underground Piping and Tanks” (LR-ISG-2011-03)	This LR-ISG provides an acceptable approach for managing the effects of aging of buried and underground piping and tanks within the scope of 10 CFR Part 54.	SER Section 3.0.3.2.12, 3.0.3.2.15, 3.5.2.3.15, and Appendix A
Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors (LR-ISG-2011-04)	This LR-ISG revises the recommendations in the GALL Report and the staff’s acceptance criteria and review procedures in the SRP-LR to ensure consistency with Materials Reliability Program (MRP)-227-A. This LR-ISG also provides a framework to ensure that PWR LRAs will adequately address age-related degradation and aging management of reactor vessel internal (RVI) components during the term of the renewed license.	SER Section 3.0.3.2.3, 3.1.2.1.3, 3.1.2.2.9, 3.1.2.2.10, 3.1.2.2.12, 3.1.2.2.13, and 3.1.2.2.14
Ongoing Review of Operating Experience (LR-ISG-2011-05)	This LR-ISG clarifies the staff’s existing position in the SRP-LR that acceptable license renewal AMPs should be informed and enhanced when necessary, based on the ongoing review of both plant-specific and industry operating experience.	SER Section 3.0.5.2.1, 3.0.5.2.2, 3.0.5.2.5, and 3.0.5.3
Wall Thinning Due to Erosion Mechanisms (LR-ISG-2012-01)	This LR-ISG provides guidance on an acceptable approach to manage the effects of aging during the period of extended operation for wall thinning due to various erosion mechanisms for piping and components within the scope of 10 CFR Part 54. This LR-ISG also GALL Report AMP XI.M17, “Flow-Accelerated Corrosion.”	SER Section 3.0.3.1.5 and 3.4.2.3.5

ISG Issue (Approved ISG Number)	Purpose	SER Section
Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation (LR-ISG-2012-02)	This LR-ISG revises existing guidance in the GALL Report and SRP-LR related to aging management of internal surfaces of components and atmospheric storage tanks. Also, it provides recommendations for corrosion under insulation (CUI) of component external surfaces.	SER Section 3.0.3.1.9, 3.0.3.1.11, 3.0.3.2.4, 3.0.3.2.11, 3.0.3.2.12, 3.0.3.3.1, and 3.5.2.3.15
Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (LR-ISG-2013-01)	This LR-ISG provides an acceptable approach for managing these associated aging effects for components within the scope of License Renewal.	The issues in this ISG are addressed in SER Section 3.0.3.3. See also Sections 3.0.3.1.11, 3.0.3.1.12, 3.0.3.2.6, 3.0.3.2.11, and 3.0.3.2.13.

1.5 Summary – Closure of Open Items

As a result of its review of the LRA, including additional information submitted through April 17, 2015, the staff closed the following open items (OIs) previously identified in the "Safety Evaluation Report with Open Items Related to the License Renewal of Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2," dated October 30, 2014 (ADAMS Accession No. ML14296A176). No other OIs remain to be addressed. An item is considered open if the staff has not made a finding under 10 CFR 54.29 (Standards for issuance of a renewed license) with respect to that particular item. A summary of the basis for each closed OI is presented here.

Open Item 3.0.3.1.3-1 CRDM Nozzle Wear

By letter dated June 18, 2014, the applicant provided its response to RAI B.2.1.5-1a. In its response to Part 1 of the RAI, the applicant stated that it is participating in a Westinghouse Owners Group project which is expected to provide a detailed analysis justifying that the control rod drive mechanism (CRDM) nozzle wear acceptance criteria can be met for the maximum possible wear depth of 0.1075 in. The applicant also stated that based on the completed feasibility study for this project, preliminary evaluations of the stresses and fatigue usages were performed to determine the approximate wear depth that could be qualified in accordance with American Society of Mechanical Engineers Code, Section III, Subsection NB. The applicant also stated that the detailed analysis was scheduled to be completed in October 2014. As a result of several communications between the staff and the applicant, the applicant submitted an amendment to its LRA which identifies an inspection program for aging management of CRDM nozzle wear. The applicant also indicated that the inspection program will be used prior to and during the period of extended operation to monitor the wear. By letter dated February 11, 2015, the applicant revised the LRA as proposed and provided detailed nondestructive examination (NDE) procedures it will implement to manage the CRDM nozzle wear. On the basis of the staff's evaluation of the applicant's response, OI 3.0.3.1.3-1 is closed. The staff's resolution and closure of this issue is documented in SER Section 3.0.3.1.3.

Open Item 4.3-1 Environmentally Assisted Fatigue (EAF) in Class 1 Components

BBS, Units 1 and 2, performed a systematic review of all wetted, reactor coolant pressure boundary components with a Class 1 fatigue analysis to either show that the NUREG/CR-6260 locations are bounding or to incorporate environmentally-assisted fatigue (EAF) into the licensing basis for those more limiting components.

The applicant performed a systematic review to determine plant-specific limiting locations to be monitored by the Fatigue Monitoring program for EAF. The applicant compared components of various materials in its EAF evaluations. The staff found that the environmentally adjusted cumulative usage factor (CUF_{en}) value of different materials may respond differently when the EAF is being refined in the future. The applicant initially did not demonstrate that the refinement of the higher CUF_{en} of one material would ensure the reduction of CUF_{en} values for another material within the same transient section such that the selected leading location would remain appropriate and bounding. The applicant subsequently provided examples of its screening methods to identify the limiting components and added three plant-specific component locations to the monitoring list. In justifying its screening methods with plant-specific examples and updating its program, the applicant has now demonstrated that the resulting limiting locations are appropriate and bounding for BBS, Units 1 and 2. The resolution and closure of this issue is documented in SER Section 4.3.1.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA, including additional information submitted through April 17, 2015, the staff determines that no confirmatory items exist which would require a formal response from the applicant.

1.7 Summary of Proposed License Conditions

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

License Condition No. 1: The first license condition will require the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed licenses. The applicant may make changes to the programs and activities described in the UFSAR supplement provided the applicant evaluates such changes in accordance with the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

License Condition No. 2: The second license condition will state that the applicant's UFSAR supplement describes certain programs to be implemented and activities to be completed before the period of extended operation. The second license condition will state that:

(a) The applicant shall implement those new programs and enhancements to existing programs no later than 6 months before the period of extended operation.

(b) The applicant shall complete those inspection and testing activities before the end of the last refueling outage before the period of extended operation or 6 months before the period of extended operation, whichever occurs later.

The second license condition will also require the applicant to notify the staff in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

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

LRA Appendix A, Section A.5, "License Renewal Commitment List," contains commitments for license renewal and an associated schedule for when the applicant plans to implement or complete the commitments. Through the commitments in LRA Appendix A, Section A.5, the applicant will implement new programs, implement enhancements to existing programs, and will also complete inspection or testing activities. Because the applicant's implementation schedule for some commitments, as provided originally in LRA Appendix A, Section A.5, could conflict with the implementation schedule intended by the generic second license condition described above, by letter dated June 17, 2014, the staff issued RAI A.1-1, which requested that the applicant provide the expected date for implementing all commitments prior to the period of extended operation and state whether the implementation would be documented as a license condition or as a supplement to the UFSAR. By letter dated December 15, 2014, the applicant responded to RAI A.1-1 and provided a revision to LRA Appendix A, Sections A.1.0.1 and A.5, in which it specified the time period when each commitment would be implemented and where it would be documented. Specifically, the applicant stated:

- Implementation of new aging management programs and enhancements to existing aging management programs will be completed no later than six months prior to the respective period of extended operation for each Byron and Braidwood unit; and

- Inspection or testing activities identified for completion prior to the period of extended operation will be completed either:
  - no later than six months prior to the respective period of extended operation for each Byron and Braidwood unit, or
  - prior to the end of the last refueling outage before the respective period of extended operation for each respective unit,

  whichever occurs later

The applicant also stated that upon receipt of the renewed license, Appendix A of the LRA will be incorporated into the Byron and Braidwood UFSAR as a UFSAR Supplement per the requirements of 10 CFR 54.21(d).

The staff finds the applicant's response to RAI A.1-1 acceptable because: (1) the staff reviewed the applicant's response and revision of LRA Appendix A and confirmed that the applicant identified those commitments that implement new programs and enhancements to existing programs and stated that these commitments will be implemented no later than 6 months before the period of extended operation, which is consistent with the proposed second license condition; (2) the staff also confirmed that as part of its response, the applicant identified the commitments that complete inspection or testing activities and stated, consistent with the proposed second license condition, that these commitments will be implemented 6 months before the period of extended operation or by the end of the last refueling outage before the period of extended operation, whichever occurs later; and (3) all commitments in LRA Appendix A will be incorporated into the Byron and Braidwood UFSARs. The staff also notes that the proposed license condition will require the applicant to notify the staff in writing within 30 days after having accomplished the implementations, and the status of the inspection or test activities, as described above. With this additional proviso, the staff's concerns described in RAI A.1-1 are resolved.

License Condition No. 3 (Braidwood Unit 2 only): The third license condition will state that, no later than 6 months prior to the period of extended operation or before the end of the last refueling outage prior to the period of extended operation (whichever occurs later), the Braidwood, Unit 2, reactor head closure stud hole location No. 35 will be repaired so that all 54 reactor head closure studs are operable and tensioned during the period of extended operation.

License Condition No. 4 (Braidwood Units 1 and 2 only): This license condition will state that the flux thimble tube corrective actions, inspections, and replacements identified in this SER, Appendix A, Commitment No. 24 for Braidwood Units 1 and 2, shall be implemented in accordance with the schedule in the Commitment. Periodic eddy current testing/inspections of all flux thimble tubes shall be performed at least every two refueling outages, and the data shall be trended and retained in auditable form. A flux thimble tube shall not remain in service for more than two (2) operating fuel cycles without successful completion of eddy current testing for that thimble tube.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

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

2.1.2 Summary of Technical Information in the Application

LRA Section 2.0, "Scoping And Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results," provides the technical information required by 10 CFR 54.21(a). LRA Section 2.0 states, in part, that the applicant had considered the following in developing the scoping and screening methodology described in LRA Section 2.0:

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

LRA Section 2.1, "Scoping and Screening Methodology," describes the methodology used by Exelon Generation Company, LLC (Exelon, the applicant) to identify the SSCs at Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, (BBS) within the scope of license renewal (scoping) and the SCs subject to an AMR (screening).

The staff reviewed the results of the applicant's implementation of scoping and screening methodology to identify SCs subject to an AMR in the following LRA sections:

- Section 2.3 for mechanical systems
- Section 2.4 for structures systems
- Section 2.5 for electrical systems

2.1.3 Scoping and Screening Program Review

The staff evaluated the applicant's scoping and screening methodology in accordance with the guidance contained in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Section 2.1, "Scoping and

Screening Methodology." The following regulations provide the basis for the acceptance criteria used by the staff to assess the adequacy of the scoping and screening methodology used by the applicant to develop the LRA:

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

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

In addition, the staff conducted a scoping and screening methodology audit at the Byron Station facilities located in Byron, Illinois, during the week of July 29 through August 2, 2013, and at the Braidwood Station, located in Braidwood, Illinois, during the week of December 2 through 4, 2013. The audit focused on ensuring that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodology described in the LRA and the requirements of the Rule. The staff reviewed the project-level guidelines, technical basis documents and implementing procedures that described the applicant's scoping and screening methodology. The staff conducted detailed discussions with the applicant on the implementation and control of the license renewal methodology, the quality practices used by the applicant during the LRA development and the training of the applicant's staff that participated in the LRA development. On a sampling basis, the staff performed a review of scoping and screening results reports and supporting current licensing basis (CLB) information for portions of the service water system, essential water service cooling towers, turbine building and structures adjacent to containment at Byron and the service water system, essential service cooling pond, turbine building and structures adjacent to containment at Braidwood. In addition, the staff performed walkdowns of selected portions of those systems and structures, as a part of the sampling review of the implementation of the applicant's 10 CFR 54.4(a)(2) scoping methodology.

The staff documented the results of the BBS scoping and screening audit in the BBS Scoping and Screening Methodology Audit Report, dated March 14, 2014. The staff required additional information to complete its review, which is further discussed in SER Sections 2.1.4.1.2, 2.1.4.2.2, and 2.1.4.6.2.

2.1.3.1 Implementation Procedures and Documentation Sources for Scoping and Screening

2.1.3.1.1 Summary of Technical Information in the Application

The applicant stated that it had developed implementing procedures, used in LRA preparation, that described the process used to review CLB documentation sources and to identify SSCs within the scope of license renewal and SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21.

LRA Section 2.1.2, "Information Sources Used for Scoping and Screening," listed the following information sources for the license renewal scoping and screening process:

- updated final safety analysis report (UFSAR)
- fire protection report
- environmental qualification master list
- maintenance rule database
- engineering drawings
- controlled plant component database

2.1.3.1.2 Staff Evaluation

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

The applicant's implementing procedures contain guidance for determining plant SSCs within the scope of the Rule and SCs, contained in systems within the scope of license renewal, that are subject to an AMR. During the review of the implementing procedures, the staff focused on the consistency of the detailed procedural guidance with information contained in the LRA, including the implementation of the staff positions documented in the SRP-LR, and the information in the applicant's responses dated December 19, 2013, to the staff's requests for additional information (RAIs) dated November 22, 2013. After reviewing the LRA and supporting documentation, the staff determined that the scoping and screening methodology instructions are consistent with the methodology description provided in LRA Section 2.1. The applicant's methodology is sufficiently detailed in the implementing procedures to provide concise guidance on the scoping and screening process to be followed during the LRA activities.

Sources of Current Licensing Basis Information. Section 54.21(a)(3) of 10 CFR requires, for each SC determined to be subject to an AMR, demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. Section 54.3(a) of 10 CFR defines the CLB, in part, as the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with, and operation within, applicable NRC requirements and the plant-specific design bases that are docketed and in effect. The CLB includes applicable NRC regulations, orders, license conditions, exemptions, 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. The staff considered the scope and depth of the applicant's CLB review to verify that the methodology is sufficiently comprehensive to identify SSCs within the scope of license renewal and as SCs requiring an AMR.

During the scoping and screening methodology audit, the staff confirmed that the applicant's detailed license renewal program guidelines specified the use of the CLB source information in developing scoping evaluations. The staff reviewed pertinent information sources used by the applicant including the UFSAR, CLB documents, fire protection report, environmental qualification master list, maintenance rule database, engineering drawings and controlled plant component database.

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

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

2.1.3.1.3 Conclusion

Based on its review of LRA Sections 2.0 and 2.1, the scoping and screening implementing procedures and the results from the scoping and screening audit, the staff concludes that the applicant's use of implementing procedures and consideration of document sources including CLB information is consistent with the Rule, the SRP-LR and NEI 95-10 guidance and, therefore, is acceptable.

2.1.3.2 Quality Controls Applied to License Renewal Application Development

2.1.3.2.1 Staff Evaluation

The staff reviewed the adequacy of the quality controls used by the applicant during the development of the LRA to ensure that LRA development activities were performed in accordance with the applicant's license renewal program requirements:

- performed scoping and screening activities using approved documents and procedures
- used databases to guide and support scoping and screening and to generate license renewal documents
- employed the standard processes for scoping, screening, and LRA preparation
- used processes and procedures that incorporate preparation, review, comment, and owner acceptance
- incorporated industry lessons learned and RAIs from other plant license renewals

- performed external assessments including a peer review and benchmarking to recent LRAs
- performed internal assessments including those performed by a challenge board, the plant operations review committee and the nuclear safety review board

During the scoping and screening methodology audit, the staff performed a review of implementing procedures and guides, examined the applicant's documentation of activities in reports, reviewed the applicant's activities performed to assess the quality of the LRA, and held discussions with the applicant's license renewal management and staff. The staff determined that the applicant's activities provide assurance that the LRA was developed consistent with the applicant's license renewal program requirements.

2.1.3.2.2 Conclusion

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

2.1.3.3 Training

2.1.3.3.1 Staff Evaluation

The staff reviewed the training process used by the applicant for license renewal project personnel to confirm that it was appropriate for the activity. As outlined in the implementing procedures, the applicant required training for personnel participating in the development of the LRA and used trained and qualified personnel to prepare the scoping and screening implementing procedures.

License renewal project personnel were trained using license renewal project procedures and other relevant license renewal information, as appropriate to their functions. Training topics had included 10 CFR Part 54, relevant NRC and industry guidance documents, lessons learned from other nuclear power plant license renewals, and applicable implementing procedures.

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

2.1.3.3.2 Conclusion

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

2.1.3.4 Conclusion of Scoping and Screening Program Review

On the basis of a review of information provided in LRA Sections 2.0 and 2.1, a review of the applicant's scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, review of the quality controls applied to the LRA development, training of personnel participating in the LRA development, and the results from the scoping and screening methodology audit, the staff concludes that the applicant's scoping and screening program is consistent with the SRP-LR and the requirements of 10 CFR Part 54 and, therefore, is acceptable.

2.1.4 Plant Systems, Structures, and Components Scoping Methodology

LRA Section 2.1, "Scoping and Screening Methodology," described the applicant's methodology used to identify SSCs within the scope of license renewal pursuant to the requirements of the 10 CFR 54.4(a) criteria. The LRA states that that the scoping process identified the SSCs that are safety-related and perform and support an intended function for responding to a design-basis event (DBE), are nonsafety-related whose failure could prevent accomplishment of a safety-related function, or support a specific requirement for one of the regulated events applicable to license renewal. In addition, the LRA states that the scoping methodology used is consistent with 10 CFR Part 54 and with the industry guidance contained in NEI 95-10.

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

2.1.4.1.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(1) in LRA Section 2.1.5.1, "Safety-Related - 10 CFR 54.4(a)(1)," which states:

> At BBS [Byron and Braidwood Stations], the safety-related plant components are identified in controlled engineering drawings and summarized in the PassPort equipment database. The safety-related classifications in the BBS PassPort equipment database were populated using a controlled procedure, with classification criteria consistent with the above 10 CFR 54.4(a)(1) criteria.

2.1.4.1.2 Staff Evaluation

As required by 10 CFR 54.4(a)(1), the applicant must consider all safety-related SSCs relied upon to remain functional during and following a 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, as applicable.

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

> The set of design basis events as defined in the rule is not limited to Chapter 15 (or equivalent) of the UFSAR. Examples of design basis events that may not be described in this chapter include external events, such as floods, storms, earthquakes, tornados, or hurricanes, and internal events, such as a high energy line break. Information regarding design basis events as defined in

> 10 CFR 50.49(b)(1) may be found in any chapter of the facility UFSAR, the Commission's regulations, NRC orders, exemptions, or license conditions within the CLB. These sources should also be reviewed to identify systems, structures, and components that are relied upon to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the functions described in 10 CFR 54.4(a)(1).

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

The staff determined that the applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criterion in accordance with the license renewal implementing procedures which provide guidance for the preparation, review, verification, and approval of the scoping evaluations to ensure the adequacy of the results of the scoping process. The staff reviewed the implementing procedures governing the applicant's evaluation of safety-related SSCs, and sampled the applicant's reports of the scoping results to ensure that the applicant applied the methodology in accordance with the implementing procedures. In addition, the staff discussed the methodology and results with the applicant's personnel who were responsible for these evaluations.

The staff reviewed the applicant's evaluation of the Rule and CLB definitions pertaining to 10 CFR 54.4(a)(1) and determined that the applicant's CLB definition of safety-related met the definition of safety-related specified in the Rule.

The staff reviewed a sample of the license renewal scoping results for portions of the service water system and essential water service cooling towers at Byron and the service water system and essential service cooling pond at Braidwood to provide additional assurance that the applicant adequately implemented their scoping methodology with respect to 10 CFR 54.4(a)(1).

The staff confirmed that the applicant developed the scoping results for each of the sampled systems consistently with the methodology, identified the SSCs credited for performing intended functions, and adequately described the basis for the results, as well as the intended functions. The staff also confirmed that the applicant had identified and used pertinent engineering and licensing information to identify the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) criteria.

The staff determined additional information was required to complete its review. RAI 2.1-1, dated November 22, 2013, states, in part:

> During the on-site scoping and screening methodology audit, the staff determined that the applicant had used a plant equipment database, which provides the component quality classification, as an information source to identify SSCs within the scope of license renewal. However, the staff determined that not all components identified as safety-related in the plant equipment database were included with the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff requested that the applicant provide a basis for not

including components identified as safety-related within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The applicant responded to RAI 2.1-1, by letter dated December 19, 2013, which states, in part:

> During the scoping phase of the development of the Byron and Braidwood license renewal application the PassPort equipment database was used as one of many sources to identify systems and structures within the scope of license renewal. The PassPort equipment database was not used to make component level scoping determinations. The scoping methodology requires the identification of all systems that perform a safety-related function for inclusion within the scope of license renewal in accordance with scoping criterion 10 CFR 54.4(a)(1). Once the systems that perform a safety-related intended function are identified, the applicable system level safety-related intended functions are determined based on a review of a number of sources including the UFSAR, design basis documents (e.g., engineering drawings, evaluations, and calculations), and the maintenance rule database. Based on the system safety-related intended functions, the components required for the system to perform the safety- related intended functions are identified and included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The applicant's letter further states:

> As a confirmatory method to ensure that all systems that perform a 10 CFR 54.4(a)(1) function are identified, the component-level safety classification field in the PassPort equipment database was reviewed. Per the Byron and Braidwood scoping methodology, if a system includes components that are identified as safety-related in the PassPort equipment database, then the system is included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) with the following exceptions:
>
> - Systems with Safety-Related Boundary Components: If the safety-related components in an otherwise nonsafety-related system are required to support the safety-related function of an interfacing system, then the safety-related components may be reassigned to the interfacing system for license renewal aging management review. The remainder of the nonsafety-related system is not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). This is consistent with the Byron and Braidwood scoping methodology in that license renewal systems are made up of station equipment grouped together by common function. For cases such as this, the specific components that are classified as safety-related are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).
> - Systems with Components with Incorrect PassPort Equipment Database Classifications: In the process of the development of the license renewal application a limited number of discrepancies were identified related to the safety classification of individual components in the PassPort equipment database at Byron and Braidwood. During the review of the component level safety-classification field in PassPort, certain systems that are classified as nonsafety-related in other sources (e.g., UFSAR) were identified as containing a limited number of components that were classified as safety-related in the

PassPort equipment database. The components identified during this review were then evaluated to determine if they perform any safety-related function. If the components do not perform a safety-related function, then the system was not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). All component level safety classification discrepancies identified during the development of the license renewal application have been entered into the corrective action program. Components that have been identified as incorrectly classified as safety-related in the PassPort equipment database but do not perform or support any safety-related function are not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

- Systems with Components with Conservative PassPort Equipment Database Classifications: As described in Section 3.1.1 of NEI 95-10, components that are not relied on to perform any safety-related function described in 10 CFR 54.4(a)(1) may be classified as safety-related because of plant-specific considerations and preferences. Therefore, a component may not meet the requirements of 10 CFR 54.4(a)(1) although it is designated as safety-related for plant-specific reasons. If the only safety-related components in an otherwise nonsafety-related system are conservatively classified as safety-related but do not perform a safety-related function then the system would not be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). Components that have been identified as conservatively classified as safety-related in the PassPort equipment database but do not perform or support any safety-related function are not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The staff reviewed the response to RAI 2.1-1 and determined that the applicant evaluated all components identified as safety-related in the plant equipment database and included those components with a safety-related intended function within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff concern in RAI 2.1-1 is resolved.

2.1.4.1.3 Conclusion

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

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

2.1.4.2.1 Summary of Technical Information in the Application

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

LRA Section 2.1.5.2, “Nonsafety-Related Affecting Safety-Related - 10 CFR 54.4(a)(2),” which states, in part:

Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions

The Byron and Braidwood UFSAR and other CLB documents were reviewed to identify nonsafety-related systems or structures required to support satisfactory accomplishment of a safety-related function. Nonsafety-related systems or structures credited in CLB documents to support a safety-related function 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 if the nonsafety-related is within the analytical boundary of the CLB seismic analysis.

In certain instances the analytical boundaries of the CLB seismic analysis are not clearly defined. In these cases the nonsafety-related piping was included in scope for 10 CFR 54.4(a)(2), up to one of the [bounding conditions used to define equivalent anchors as discussed in NEI 95-10, Appendix F].

Potential for Spatial Interactions with Safety-Related SSCs

Nonsafety-related systems that are not connected to safety-related piping or components, or are outside the structural support boundary for the attached safety-related piping system, 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.

2.1.4.2.2 Staff Evaluation

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

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

Nonsafety-Related SSCs Required To Perform a Function That Supports a Safety-Related SSC. The staff reviewed LRA Section 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure that described the method used to identify and include nonsafety-related SSCs, required to perform a function that supports a safety-related SSC intended function, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff confirmed that the applicant reviewed the UFSAR, plant drawings, the controlled 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 staff determined that the applicant identified the nonsafety-related SSCs required to perform a function that supports a safety-related SSC and appropriately included the nonsafety-related SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The staff determined that the applicant's methodology for identifying nonsafety-related systems that perform functions that support safety-related intended functions, for inclusion within the scope of license renewal, is in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

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

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

- seismic anchors
- equivalent anchors
- bounding conditions described in NEI 95-10 Revision 6, Appendix F (base-mounted component, flexible connection, inclusion to the free end of nonsafety-related piping, inclusion of the entire piping run or a branch line off of a header where the moment of inertia of the header is greater than 7 times the moment of inertia of the branch)

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

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

The staff determined additional information would be required to complete its review. RAI 2.1-2, dated November 22, 2013, states, in part:

> During the on-site scoping and screening methodology audit, the staff determined that certain equipment that was no longer required had been placed in an abandoned state. The applicant indicated that activities had been performed to confirm that abandoned equipment that initially contained fluids, and is in the proximity of safety-related SSCs, has been verified to be drained. The staff requests that the applicant provide a basis for not including abandoned equipment within the scope of license renewal in accordance with 10 CFR 54.4(a).

The applicant responded to RAI 2.1-2, by letter dated December 19, 2013, which states, in part:

> The basis and methodology for not including abandoned equipment within the scope of license renewal is that the abandoned equipment did not meet any of the scoping criteria as delineated in 10 CFR 54.4(a). Abandoned equipment is not relied on to perform any function delineated in 10 CFR 54.4(a)(1) or (a)(3) as it is non-operational. However, failure of abandoned equipment could potentially impact the performance of the safety-related function of surrounding equipment if the abandoned equipment contains water, steam, or oil. The abandoned equipment that has been excluded from scope has been vented, fluids drained, and isolated, and therefore this equipment does not perform any intended function for license renewal. This information was verified through review of documents including drawings, procedures, and design change packages, as well as discussions with site personnel.

The applicant's response further stated, "Any abandoned equipment located in an area containing safety-related equipment, that was not verified to be drained of fluids, is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2)."

The staff reviewed the applicant's response to RAI 2.1-2 and determined that the applicant performed a review to identify equipment that had been abandoned in-place. The staff determined that the applicant included abandoned equipment, that had not been confirmed to be drained of fluids and whose failure could impact safety-related SSCs, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff concern in RAI 2.1-2 is resolved.

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

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

2.1.4.2.3 Conclusion

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

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

2.1.4.3.1 Summary of Technical Information in the Application

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

LRA Section 2.1.5.3, "Regulated Events - 10 CFR 54.4(a)(3)," states:

> In accordance with 10 CFR 54.4(a)(3), the systems, structures, and components within the scope of license renewal include: 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 fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.61), and station blackout (10 CFR 50.63).

LRA Section 2.1.5.3 also states:

> For each of the five regulations, a technical basis document was prepared to provide input into the scoping process. Each of the regulated event basis documents (described in Section 2.1.3.4 [of the LRA]) 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. Guidance provided by the technical basis documents was incorporated into the system and structure scoping evaluations, to determine the SSCs credited for each of the 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.

2.1.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.1.5.3 that described the method used to identify, and include within the scope of license renewal, those SSCs, relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), pressurized thermal shock (PTS) (10 CFR 50.61), anticipated transients without scram (ATWS) (10 CFR 50.62), and station blackout (SBO) (10 CFR 50.60). As part of this review, during the scoping and screening methodology audit the staff held discussions with the applicant, and reviewed implementing procedures and the technical basis documents, license renewal drawings, and scoping results reports. The staff determined that the applicant evaluated the CLB to identify SSCs that perform functions addressed in 10 CFR 54.4(a)(3) and included these SSCs within the scope of license renewal as documented in the scoping reports. In addition, the staff determined that the scoping report results referenced the information sources used for determining the SSCs credited for compliance with the events.

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

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

Pressurized Thermal Shock (PTS). The staff reviewed the applicant's implementing procedure and technical basis document that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (Pressurized Thermal Shock – 10 CFR 50.61). The technical basis document described the process to review the licensing basis for PTS at Byron and Braidwood. The only component within the scope of license renewal for PTS is the reactor pressure vessel (RPV). The staff reviewed portions of the applicable portions of the LRA, CLB information, and license renewal drawings, to verify the appropriate SSCs were included within the scope of license renewal. Based on its review of the CLB documents and the technical basis document, the staff found the applicant's methodology adequate for identifying and including the RPV in performing PTS functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

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

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

2.1.4.3.3 Conclusion

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

2.1.4.4 Plant-Level Scoping of Systems and Structures

2.1.4.4.1 Summary of Technical Information in the Application

System and Structure Level Scoping. The applicant described the methods used to identify SSCs included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a) in LRA Section 2.0, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results," which states:

> This section describes the process for identifying structures and components subject to aging management review in the Byron and Braidwood Stations (BBS) license renewal integrated plant assessment. For the systems, structures, and components (SSCs) within the scope of license renewal, 10 CFR 54.21(a)(1) requires the license renewal applicant to identify and list those structures and components subject to Aging Management Review (AMR). 10 CFR 54.21(a)(2) further requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified.

2.1.4.4.2 Staff Evaluation

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

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

2.1.4.4.3 Conclusion

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

2.1.4.5 Mechanical Component Scoping

2.1.4.5.1 Summary of Technical Information in the Application

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

LRA Section 2.1.5, “Scoping Procedure,” states, in part:

> 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 described in Section 2.1.6 [of the LRA].

LRA Section 2.1.5.5, “Scoping Boundary Determination,” states, in part:

> Systems and structures that are included within the scope of license renewal are then further evaluated to determine the population of in scope structures and components. This part of the scoping process is also a transition from the scoping process to the screening process. The process for evaluating

> mechanical systems is different from the process for structures, primarily because the plant design document formats are different. Mechanical systems are depicted primarily on the system piping and instrumentation diagrams (P&ID) that show the system components and their functional relationships…

LRA Section 2.1.5.5 further states, in part:

> For mechanical systems, the mechanical components that support the system intended functions are included within the scope of license renewal and are depicted on the applicable system piping and instrumentation diagram.

2.1.4.5.2 Staff Evaluation

The staff reviewed LRA Sections 2.1.5 and 2.1.5.5, implementing procedures, reports and the CLB source information associated with mechanical scoping. The staff determined that the CLB source information and the implementing procedure guidance used by the applicant was acceptable to identify mechanical SSCs within the scope of license renewal. The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant appropriately applied the scoping methodology outlined in the LRA and implementing procedures and whether the scoping results were consistent with CLB requirements. The staff found the applicant's procedure to be consistent with the description provided in the LRA Sections 2.1.5 and 2.1.5.5 and the guidance contained in the SRP-LR, Section 2.1, and adequately implemented.

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

2.1.4.5.3 Conclusion

On the basis of its review of information contained in the LRA and implementing procedures, the sampling review of 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

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

LRA Section 2.1.5, "Scoping Procedure," states, in part:

> 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 described in Section 2.1.6 [of the LRA].

LRA Section 2.1.5.5, "Scoping Boundary Determination," states, in part:

> Systems and structures that are included within the scope of license renewal are then further evaluated to determine the population of in scope structures and components. This part of the scoping process is also a transition from the scoping process to the screening process. The process for evaluating mechanical systems is different from the process for structures, primarily because the plant design document formats are different. Mechanical systems are depicted primarily on the system piping and instrumentation diagrams (P&ID) that show the system components and their functional relationships while structures are depicted on physical drawings. Electrical and I&C components of in scope electrical and in scope mechanical systems are placed into commodity groups and are screened as commodities. Scoping boundaries for mechanical systems, structures, and electrical are, therefore, described separately.

LRA Section 2.1.5.5 further states, in part:

> For structures, the structural components that are required to support the intended function(s) of the structure, as described in the CLB, are included within the scope of license renewal. The structural components are identified from a review of applicable plant design drawings of the structure.

2.1.4.6.2 Staff Evaluation

The staff reviewed LRA Sections 2.1.5 and 2.1.5.5, implementing procedures, reports and the CLB source information associated with structural scoping. The staff found the CLB source information and the implementing procedure guidance used by the applicant acceptable to identify structural SSCs within the scope of license renewal. The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant appropriately applied the scoping methodology outlined in the LRA and implementing procedures and whether the scoping results were consistent with CLB requirements. The staff found the applicant's procedure to be consistent with the description provided in the LRA Sections 2.1.5 and 2.1.5.5 and the guidance contained in the SRP-LR, Section 2.1, and adequately implemented.

On a sampling basis, the staff reviewed the applicant's scoping reports for portions of the essential water service cooling towers, turbine building and structures adjacent to containment at Byron and the essential service cooling pond, turbine building and structures adjacent to containment at Braidwood, and the process used to identify structural systems and component that met the scoping criteria of 10 CFR 54.4. The staff reviewed the implementing procedures, confirmed that the applicant used pertinent engineering and licensing information, and discussed the methodology and results with the applicant. As part of the review process, the staff evaluated the structure's documented intended functions and the process used to identify structural component types. Additionally, the staff determined that the applicant confirmed the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results performed independent reviews of the scoping reports and the applicable license renewal drawings. The staff confirmed that the SCs identified by the applicant were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff confirmed that the applicant used pertinent engineering and licensing information in order to determine that systems and components were included within the scope of license renewal in accordance with the 10 CFR 54.4(a).

In RAI 2.1-3, dated November 22, 2013, the staff stated, in part:

> During the on-site scoping and screening methodology audit, the staff reviewed the license renewal application, license renewal implementing documents, as-built drawings, and current licensing basis documentation. The staff determined that the containment access facility hallway structure that is immediately adjacent to the containment extension structure (within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)) is not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff requests that the applicant provide a basis for not including the containment access facility hallway structure, which is located adjacent to containment extension structure (within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)), within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-3, by letter dated December 19, 2013, which states, in part:

> Due to the location of the CAF [containment access facility] hallway structures with respect to the safety-related structures, spatial interaction between the buildings was considered. Byron and Braidwood UFSAR Section 3.3.2.3 was reviewed and found to provide a description of the evaluation of the collapse of the CAF hallway structures, referred to as the equipment staging structures adjacent to the emergency hatch, on safety-related structures under tornado loadings. It was concluded that although the nonsafety-related CAF hallway structures were not designed for tornado loading conditions, their collapse and failure during a tornado event would not adversely affect the structural integrity of any safety-related structures. Furthermore, missiles generated as a result of the collapse of CAF hallway structure were evaluated and determined to be less critical than those considered in UFSAR Subsection 3.5.1.4. At the time of the original scoping evaluation of the CAF hallway structures, this tornado loading analysis was considered to bound the failure of the structures due to age-related

> reasons as the loads imparted on safety-related structures in a tornado event would exceed the loads experienced as a result of the potential collapse of the structures due to aging. In addition, the potential failure modes of the CAF hallway structures due to tornado loads are not limited by any design features, such that the effects of age-related degradation of the CAF hallway structures cannot exceed the results of this tornado analysis. Therefore, the scoping methodology did not preclude SSCs from being included within the scope of license renewal in accordance 10 CFR 54.4(a)(2).

The applicant's response further stated:

> However, the Staff's concern is recognized relative to the absence of a formal analysis, evaluation, or calculation documenting the potential age-related failure effect of the CAF hallway structures on nearby safety-related structures. Based on a review of this issue, the portions of the CAF hallway structures that are in contact with, or immediately adjacent to, safety-related structures at Byron and Braidwood Stations will be included within the scope of license renewal under 10 CFR 54.4(a)(2). The CAF hallway structures are now evaluated as part of the Containment Structure as an additional exterior structural feature.

The staff reviewed the applicant's response to RAI 2.1-3 and determined that the applicant performed a review and determined that the nonsafety-related containment access facility, adjacent to the containment extension structure, would be included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). The staff concern in RAI 2.1-3 is resolved.

2.1.4.6.3 Conclusion

On the basis of its review of information contained in the LRA and implementing procedures, the sampling review of scoping results, and the applicant's response to RAI 2.1-3, the staff concludes that the applicant's methodology for identifying 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

LRA Section 2.1.5, "Scoping Procedure," states, in part:

> 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 described in Section 2.1.6 [of the LRA].

LRA Section 2.1.5.5, “Scoping Boundary Determination,” states, in part:

> Systems and structures that are included within the scope of license renewal are then further evaluated to determine the population of in scope structures and components. This part of the scoping process is also a transition from the scoping process to the screening process. The process for evaluating mechanical systems is different from the process for structures, primarily because the plant design document formats are different. Mechanical systems are depicted primarily on the system piping and instrumentation diagrams (P&ID) that show the system components and their functional relationships while structures are depicted on physical drawings. Electrical and I&C components of in scope electrical and in scope mechanical systems are placed into commodity groups and are screened as commodities. Scoping boundaries for mechanical systems, structures, and electrical are, therefore, described separately.

LRA Section 2.1.5.5 further states:

> 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 within the scope of license renewal. In scope electrical components were placed into commodity groups and were evaluated as commodities during the screening process as described in Section 2.1.6 [of the LRA].

2.1.4.7.2 Staff Evaluation

The staff reviewed LRA Sections 2.1.5 and 2.1.5.5, implementing procedures, reports and the CLB source information associated with electrical scoping. The staff found that the CLB source information and implementing procedures’ guidance used by the applicant acceptable to identify electrical SSCs within the scope of license renewal. The staff conducted detailed discussions with the applicant’s license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant appropriately applied the scoping methodology outlined in the LRA and implementing procedures and whether the scoping results were consistent with CLB requirements. The staff found the applicant’s procedure to be consistent with the description provided in the LRA Sections 2.1.5 and 2.1.5.5, and the guidance contained in the SRP-LR, Section 2.1, and adequately implemented.

The staff noticed that after the scoping of electrical and instrumentation and controls (I&C) components was performed, the in-scope electrical components were categorized into electrical commodity groups. Commodity groups include electrical and I&C components with common characteristics. Component level intended functions of the component types were identified. As part of this review, the staff discussed the methodology with the applicant, reviewed the implementing procedures developed to support the review, and reviewed the scoping results for a sample of SSCs that were identified within the scope of license renewal. The staff determined that the applicant scoping included appropriate electrical and I&C components and as well as electrical and I&C components contained in mechanical or structural systems within the scope of license renewal on a commodity basis.

2.1.4.7.3 Conclusion

On the basis of its review of information contained in the LRA and implementing procedures and the sampling review of scoping results, the staff concludes that the applicant's methodology for identifying electrical 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 Conclusion for Scoping Methodology

On the basis of its review of information contained in the LRA and implementing procedures, and a sampling review of scoping results, the staff concludes that the applicant's scoping methodology 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 intended functions, and (3) that are necessary to demonstrate compliance with the NRC regulations for fire protection, EQ, PTS, ATWS, and SBO. The staff concluded that the applicant's methodology is consistent with the requirements of 10 CFR 54.4(a), and, therefore, is acceptable.

2.1.5 Screening Methodology

2.1.5.1 General Screening Methodology

2.1.5.1.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1, "Identification of Structures and Components Subject to AMR," which states, in part:

> 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 Section 2 - Scoping and Screening Methodology and Results identify the passive, long-lived structures and components within the scope of license renewal that are 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 BBS structures and components subject to aging management review 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 and that are subject to an AMR. The IPA must identify components that perform an intended function without moving parts or a change in configuration or properties (passive), as well as components that are not subject to periodic replacement based on a qualified life or specified time period (long-lived). In addition, the IPA must include a description and justification of the methodology used to identify passive and long-lived SCs, and a demonstration that the effects of aging on those SCs will be adequately managed so that the intended function(s) will be maintained under all design conditions imposed by the plant-specific CLB for the period of extended operation.

The staff reviewed the methodology used by the applicant to identify the mechanical, structural and electrical SSCs within the scope of license renewal that are subject to an AMR. The applicant implemented a process for determining which SCs were subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). The staff determined that the screening process evaluated the component types and commodity groups, included within the scope of license renewal, to determine which ones were long-lived and passive and therefore subject to an AMR. The staff reviewed on a sampling basis the screening results reports for the service water system and the turbine building. The applicant provided the staff with a detailed discussion of the processes used for each discipline and provided administrative documentation that described the screening methodology. Specific methodology for mechanical, structural and electrical SCs is discussed in SER Section 2.1.6.

2.1.5.1.3 Conclusion

On the basis of a review of the LRA, the implementing procedures, and a sampling of screening results, the staff concludes that the applicant's screening methodology is consistent with the guidance contained in the SRP-LR and is 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 the SCs that are subject to an AMR is consistent with the requirements of 10 CFR 54.21 and, therefore, is acceptable.

2.1.5.2 Mechanical Component Screening

2.1.5.2.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify mechanical SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1, states, in part:

> These system boundary drawings were reviewed to identify the passive, long-lived components, and the identified components were then entered into the license renewal database. Component listings from the PassPort equipment 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 applicant's methodology used for mechanical component screening as described in LRA Section 2.1.6, implementing procedures, basis documents, and the mechanical scoping and screening reports. The staff determined that the applicant used the screening process described in these documents along with the information contained in NEI 95-10 Appendix B and the SRP-LR, to identify the mechanical SCs subject to an AMR.

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

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. The staff reviewed the service water system screening report and basis documents, and confirmed proper implementation of the screening process (for both Byron and Braidwood).

2.1.5.2.3 Conclusion

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

2.1.5.3 Structural Component Screening

2.1.5.3.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify structural SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1 states, in part:

> The structure screening process also began with the results from the scoping process. 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 reviewed to identify the passive, long-lived structures and components, and the identified structures and components were then entered into the license renewal database. 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 applicant's methodology used for structural component screening as described in LRA Section 2.1.6.1, implementing procedures, basis documents, and the structural scoping and screening reports. The staff determined that the applicant used the screening process described in these documents along with the information contained in NEI 95-10 Appendix B and the SRP-LR, to identify the structural SCs subject to an AMR.

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

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. The staff reviewed the essential service water cooling towers (SXCTs) screening report and basis documents (for Byron) and the essential service cooling pond screening report (for Braidwood), and confirmed proper implementation of the screening process.

2.1.5.3.3 Conclusion

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

2.1.5.4 Electrical Component Screening

2.1.5.4.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify electrical SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1 states, in part:

> Screening of electrical and I&C components within the in scope electrical, I&C, and mechanical systems used a bounding approach as described in NEI 95-10. Electrical and I&C components for the in scope systems were assigned to commodity groups. The commodities subject to an aging management review are identified by applying the criteria of 10 CFR 54.21(a)(1). This method provides the most efficient means for determining the electrical commodities subject to an aging management review since many electrical and I&C components and commodities are active.

2.1.5.4.2 Staff Evaluation

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

The staff determined that the applicant identified electrical 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 the identified passive commodities to determine which were not subject to replacement based on a qualified life or specified time period (long-lived) and that the remaining passive, long-lived components were determined to be subject to an AMR.

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

2.1.5.4.3 Conclusion

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

2.1.5.5 Conclusion for Screening Methodology

On the basis of its review of the LRA, the screening implementing procedures, and a sample review of screening results, the staff concludes that the applicant's screening methodology is consistent with the guidance contained in the SRP-LR and identified those passive, long-lived components within the scope of license renewal 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, sample system reviews, the applicant's responses dated December 19, 2013, to the staff's RAIs dated November 22, 2013, the staff concludes that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff also concludes that the applicant's description and justification of its scoping and screening methodology are adequate to meet the requirements of 10 CFR 54.21(a)(1). From this review, the staff concludes that the applicant's methodology for identifying systems and structures within the scope of license renewal and SCs requiring an AMR is acceptable.

2.2 Plant-Level Scoping Results

2.2.1 Introduction

LRA Section 2.1 describes the methodology for identifying SSCs within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which SSCs must be included within the scope of license renewal.

The staff reviewed the plant-level scoping results to determine if the applicant properly identified the following 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 for 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 mechanical, 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 plant's CLB, other CLB information relating to nonsafety-related systems and structures, and certain regulated events, the applicant identified plant-level systems and structures within the scope of license renewal, as defined by 10 CFR 54.4.

2.2.3 Staff Evaluation

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

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

In RAI 2.2-1, dated February 28, 2014, the staff noticed LRA Section 2.2, Table 2.2-1 provides the results of applying the license renewal scoping criteria to the SSCs. The license renewal scoping criteria is described in Section 2.1. The following UFSAR systems are not located in LRA Table 2.2-1.

UFSAR Section	System
3.9.2.7 Loose Parts Monitoring System	Loose Parts Monitoring System
E.17 Plant Safety Parameter Display System	Safety Parameter Display System

By letter dated February 10, 2014, the staff issued RAI 2.2-1, requesting the applicant to justify the exclusion of these systems from Table 2.2-1.

By letter dated February 28, 2014, the applicant stated the loose parts monitoring system is evaluated with the Miscellaneous Instrumentation System, which is described in UFSAR

Section 3.9.2.7 as shown in LRA Table 2.2-1. The plant safety parameter display system is evaluated with the Plant Alarm and Annunciator System as shown in LRA Table 2.2-1.

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

2.2.4 Conclusion

The staff reviewed LRA Section 2.2, the RAI response, and the UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal. On the basis of its review the staff concludes that the applicant 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

The staff reviewed the results of the applicant's implementation of scoping and screening methodology to confirm that the LRA identified all the mechanical systems and components that would be subject to an AMR. Specifically, this section discusses:

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

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 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 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 the guidance in SRP-LR Section 2.3 and took into account the system function(s) described in the UFSAR. The objective was to determine if the applicant, in accordance with 10 CFR 54.4, identified 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 under 10 CFR 54.4(a), the staff confirmed 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 identified the remaining SCs subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

LRA Section 2.3.1 identifies the reactor vessel, internals, and RCS SCs subject to an AMR for license renewal.

The applicant described the supporting SCs of the reactor vessel, internals, and RCS in the following LRA sections:

- LRA Section 2.3.1.1, "Reactor Coolant System"
- LRA Section 2.3.1.2, "Reactor Vessel"
- LRA Section 2.3.1.3, "Reactor Vessel Internals"
- LRA Section 2.3.1.4, "Steam Generators"

2.3.1.1 Reactor Coolant System

2.3.1.1.1 Summary of Technical Information in the Application

The applicant stated that the RCS is a normally operating, mechanical system designed to circulate subcooled reactor coolant to transfer heat from the reactor core to the secondary fluid in four (4) steam generators during normal operation, or AOOs. 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 consists of the following plant systems:

- RCS
- reactor coolant pressurizer system
- reactor vessel level instrumentation system (a plant subsystem of the RCS)
- incore thermocouple system
- incore flux mapping system

The purpose of the RCS is to circulate reactor coolant either by forced circulation with the four RCPs or by natural circulation to transfer sufficient heat from the reactor core to the secondary fluid in the four steam generators during normal operation, DBEs, and AOOs so that reactor pressure and reactor core thermal limits are not exceeded. The RCS provides a reactor coolant pressure boundary to separate fission products from the environment. The RCS provides a core cooling flow path for decay heat removal during cold shutdown and refueling conditions to the residual heat removal (RHR) system. The RCS provides a flow path for emergency core cooling from the safety injection system (SIS). Included in the RCS is the ASME Class 1 piping and components in the interconnecting plant systems such as the RHR system, the chemical and volume control system (CVCS), and the SIS.

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

- to provide reactor coolant pressure boundary
- to sense process conditions and generate signals for reactor trip or engineered safety features (ESFs) actuation
- to remove residual heat from the RCS
- to provide and maintain sufficient reactor coolant inventory for core cooling
- to provide primary containment boundary
- to maintain the dose consequences within the guidelines of 10 CFR 50.67 or 10 CFR 100
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Anticipated Transients Without SCRAM (10 CFR 50.62)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for SBO (10 CFR 50.63)

Additional details of the RCS are provided in the UFSAR Sections 3.9.3, 5.1, 5.2, 5.4, 7.7.1.9, and E.31.

LRA Table 2.3.1-1, “Reactor Coolant System,” lists the component types that require AMR.

2.3.1.1.2 Staff Evaluation

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

2.3.1.1.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the RCS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RCS components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Vessel

2.3.1.2.1 Summary of Technical Information in the Application

The applicant stated that the reactor vessel is a normally operating, mechanical system designed to contain the pressure and heat generated by the nuclear core and transfer this heat to the RCS. The reactor vessel consists of the RPV, control rod drive mechanisms (CRDMs), integral reactor vessel head assembly, and the valves and piping associated with the RPV head vent and reactor vessel flange leakage monitoring. The reactor vessel is within the scope of license renewal.

The purpose of the Reactor Vessel is to maintain the reactor coolant pressure boundary and provide structural support for the reactor vessel internals (RVIs), nuclear fuel, incore instrumentation, and CRDMs. The Reactor Vessel provides a boundary to prevent fission product release to the environment. The CRDMs maintain the reactor coolant pressure boundary and provide a means of reactivity control in the reactor by monitoring and controlling the motion and position of the rod cluster control assemblies (RCCAs). The integral reactor vessel head assembly provides seismic support of the CRDMs and missile protection. The RPV head vent maintains the reactor coolant pressure boundary and provides a method of venting non-condensable gases from the reactor vessel and the RCS. The reactor vessel flange leakage monitoring provides a method of detecting reactor vessel flange O-ring seal leakage.

The RPV accomplishes the specified purpose by providing a reactor coolant pressure boundary for the circulation of fluid from the RCS and by providing structural support for the RVIs, incore instrumentation, and CRDMs during normal operations and DBEs. Forced reactor coolant flow from the RCS piping enters the reactor vessel through four primary inlet nozzles, flows downward through the annulus between the core barrel and the vessel wall and enters the bottom head region. The reactor coolant flow then travels upwards though the core support and lower core plate, up through the nuclear core, absorbing heat from the fuel assemblies, and exits the reactor through the four primary outlet nozzles where the reactor coolant continues through the RCS piping to the respective steam generator. A small portion of the coolant flows between the baffle plates and the core barrel to provide additional cooling of the core barrel. Similarly, a small amount of the entering flow is directed into the vessel head plenum and exits through the vessel outlet nozzles.

The intended functions of the Reactor Vessel component types within the scope of license renewal include:

- to provide reactor coolant pressure boundary
- to maintain reactor core assembly geometry
- to achieve and maintain the reactor core subcritical for any mode of normal operation or event
- to introduce emergency negative reactivity to make the reactor subcritical
- to provide physical support, shelter, and protection for safety-related SSCs
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function

- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for PTS(10 CFR 50.61)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for ATWS (10 CFR 50.62)
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for SBO (10 CFR 50.63)

Additional details of the Reactor Vessel are provided in the UFSAR Sections 4.6, 5.1, 5.2, 5.3, 9.1.4, E.19, and E.31.

LRA Table 2.3.1-2, "Reactor Vessel," lists the component types that require AMR.

2.3.1.2.2 Staff Evaluation

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

2.3.1.2.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the RPV components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RPV components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessel Internals

2.3.1.3.1 Summary of Technical Information in the Application

The applicant stated that RVIs are part a normally operating, mechanical system designed to maintain reactor core assembly geometry, to achieve and maintain the reactor core subcritical for any mode of operation or DBE, and to introduce negative reactivity to make the reactor subcritical.

RVIs consist of the upper core support structure, the lower core support structure, and the incore instrumentation support structure, where each of these major components has distinct purposes. The RVIs also include the fuel assemblies and the RCCAs that are supported by all three structures. The RVIs are within the scope of license renewal.

The overall purpose of RVIs is to direct reactor coolant flow through the fuel assemblies and other components to meet heat transfer performance requirements for all modes of operation, maintain alignment between fuel assemblies and RCCAs to achieve and maintain the reactor core subcritical for any mode of operation or DBE, and introduce negative reactivity to make the reactor subcritical. The Reactor Internals also provides support for and guides incore instrumentation.

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

- to maintain reactor core assembly geometry
- to achieve and maintain the reactor core subcritical for any mode of normal operation or event
- to introduce emergency negative reactivity to make the reactor subcritical
- relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Fire Protection (10 CFR 50.48)

Additional details of the RVIs are provided in the UFSAR Sections 3.9.5, 4.2, 4.5.2, and 5.2.

LRA Table 2.3.1-3, "Reactor Vessel Internals," lists the component types that require AMR.

2.3.1.3.2 Staff Evaluation

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

2.3.1.3.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the RVI components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RVI components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Steam Generators

2.3.1.4.1 Summary of Technical Information in the Application

The applicant stated that the steam generator system is a normally operating, mechanical system designed to serve as a heat sink for the reactor coolant, to supply dry saturated steam to the turbine, and to provide a barrier to prevent fission products and activated corrosion products in the reactor coolant from entering the steam system or environment.

The Steam Generator System consists of the following components and plant systems: steam generators (part of the RCS) and the steam generator blowout system. The Steam Generators are within the scope of license renewal.

The major components of the Steam Generator System are the four (4) steam generators per unit. Byron and Braidwood Unit 1 have Babcock & Wilcox recirculating vertical inverted u-tube steam generators. Byron and Braidwood Unit 2 have Westinghouse D-5 recirculating vertical inverted u-tube steam generators. The steam generator blowdown system consists of the blowdown condensers, hotwell tanks, blowdown condenser hotwell pumps, piping, and valves.

The purpose of the steam generators is to transfer heat from the reactor coolant to the main feedwater through the four steam generators during normal operation and AOOs so that reactor core thermal limits are not exceeded and to produce dry saturated steam for the main turbine.

The intended functions of the Steam Generator component types within the scope of license renewal include:

- to provide reactor coolant pressure boundary
- to sense process conditions and generate signals for reactor trip or ESFs actuation
- to provide primary containment boundary
- to remove residual heat from the RCS
- to provide secondary heat sink
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for ATWS (10 CFR 50.62)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for SBO (10 CFR 50.63)

Additional details of the Steam Generator are provided in the UFSAR Sections 5.2.3, 5.4.2, 7.2.2.3.5, 7.7.1.21, and 10.4.8.

LRA Table 2.3.1-4, “Steam Generators,” lists the component types that require AMR.

2.3.1.4.2 Staff Evaluation

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

2.3.1.4.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the steam generator components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the steam generator components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 identifies the ESF SCs subject to an AMR for license renewal.

The applicant described the supporting SCs of the ESFs in the following LRA sections:

- LRA Section 2.3.2.1, "Combustible Gas Control System"
- LRA Section 2.3.2.2, "Containment Spray System"
- LRA Section 2.3.2.3, "Residual Heat Removal System"
- LRA Section 2.3.2.4, "Safety Injection System"

2.3.2.1 Combustible Gas Control System

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 states the purpose of the combustible gas control system is to limit the concentrations of hydrogen in containment following a loss-of-coolant accident (LOCA). The combustible gas control system consists of the electric hydrogen recombiners and hydrogen monitors. The portion of the combustible gas control system that recombines hydrogen and oxygen into water is safety-related.

The intended functions of the combustible gas control system within the scope of license renewal include:

- to provide primary containment boundary
- to control and reduce hydrogen concentrations in containment following a LOCA
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Environmental Qualification (10 CFR 50.49)

LRA Table 2.3.2-1 identifies the component types within the scope of license renewal and subject to an AMR.

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1 and UFSAR Sections 6.2.5, 9.4.9.3 and AMR Table 3.2.2-1, and LRA Table 2.3.2-1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.1.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3.2.1.2 and on a review of the LRA, UFSAR, and drawings, the staff concluded that the applicant appropriately identified the Combustible Gas Control System components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the Combustible Gas System components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Containment Spray System

2.3.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 states the purpose of the containment spray system (CSS) is to remove heat from the containment following a LOCA or main steamline break (MSLB) to reduce the containment ambient temperature and pressure. The CSS also adds sodium hydroxide to the spray to control the sump pH, which minimizes corrosion to safety-related components following a LOCA. The CSS consists of containment spray pumps, eductors, spray nozzle headers, spray additive tank, and the associated piping, valves, instrumentation, and controls.

The intended functions of the CSS within the scope of license renewal include:

- to sense process conditions and generate signals for reactor trip or engineering safety features actuation
- to maintain primary containment integrity
- to provide heat removal from primary containment and provide primary containment pressure control
- to provide removal of radioactive material from the primary containment atmosphere
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Fire Protection (10 CFR 50.48)

LRA Table 2.3.2-2 identifies the component types within the scope of license renewal and subject to an AMR.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 and UFSAR Sections 6.2.2, 6.5.2, 15.6.5 and Table A1.183, and LRA Table 3.2.2-2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.2.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3.2.2 and on a review of the LRA, UFSAR, and drawings, the staff concluded that the applicant appropriately identified the CSS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the CSS components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Residual Heat Removal System

2.3.2.3.1 Summary of Technical Information in the Application

The applicant stated that the residual heat removal (RHR) system is a standby, mechanical emergency core cooling system (ECCS) designed to provide low pressure injection flow and long-term core cooling following DBEs. The system is designed to maintain core cooling for larger break sizes by providing low pressure injection independent of and in addition to the high-pressure and intermediate-pressure injection provided by the CVCS and SIS, respectively. During normal startup and shutdown operations, the RHR system is designed to remove decay heat from the core and residual heat from the RCS to the Component Cooling System when RCS pressure is low. The RHR system consists of the RHR system and portions of the safety injection plant systems. The RHR system is within the scope of license renewal.

The purpose of the RHR system is to inject borated water into the core following a LOCA for long-term emergency core cooling. The RHR system accomplishes this purpose by taking suction from the refueling water storage tank (RWST) and injecting into the reactor vessel through the SIS when RCS pressure decreases below RHR pump discharge pressure. The RHR pumps recirculate a minimum cooling flow to their suction, until the RCS pressure decreases below RHR pump discharge pressure. When the RWST level reaches the low-low level, suction is manually aligned to the containment sump, permitting recirculation and cooling of the reactor coolant and injection water discharged from the LOCA break. A portion of this transfer to the containment sump is performed by the automatic switchover system (evaluated with the Reactor Protection System), while the remainder of the alignment is performed by the operator.

After a small break LOCA, the reactor pressure may remain above the shutoff head of the RHR pumps even when the RWST inventory has been reduced to the minimum level. In this event, the RHR can be aligned to provide flow from the containment sump to the suction of the high-pressure CVCS pumps and intermediate-pressure SIS pumps, to allow continued high and intermediate pressure injection.

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

- to provide reactor coolant pressure boundary
- to achieve and maintain the reactor core subcritical for any mode of normal operation or event
- to introduce emergency negative reactivity to make the reactor subcritical
- to remove residual heat form the RCS
- to provide and maintain sufficient reactor coolant inventory for core cooling
- to introduce negative reactivity
- to provide primary containment boundary
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

Additional details of the RHR system are provided in the UFSAR Sections 5.4.7, 6.1.3, 6.3.2, and 7.6.4.

LRA Table 2.3.2-3, "Residual Heat Removal System," lists the component types that require AMR.

2.3.2.3.2 Staff Evaluation

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

2.3.2.3.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the RHR components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RHR components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Safety Injection System

2.3.2.4.1 Summary of Technical Information in the Application

The applicant stated that the SIS is a standby, mechanical emergency core cooling system (ECCS) designed to provide emergency core cooling following a LOCA or MSLB in the containment structure. Borated water from the RWST is injected into the RCS in order to remove decay heat from the reactor core and to prevent fuel and clad damage. This capability limits the fuel clad temperature and ensures that the core will remain substantially intact and in place, while preserving its heat transfer geometry. In addition, the SIS adds shutdown reactivity, when reactor coolant pressure does not drop below the safety injection accumulator pressure for injection to prevent an uncontrolled return to power. The SIS is within the scope of license renewal.

The SIS consists of the safety injection plant system, portions of the RHR plant system, and portions of the CVCS that perform the emergency core cooling function. The SIS consists of the following components: high-pressure injection flow paths from the centrifugal charging pumps, low-pressure injection flow paths from the RHR pumps, intermediate-pressure flow paths from the safety injection pumps, safety injection accumulators, RWST, and the necessary piping, valves, controls and instrumentation. The centrifugal charging pumps and RHR pumps are evaluated in the CVCS and the RHR system, respectively, but their ECCS functioning components (piping and major valves) are included in the SIS.

The major purposes of the SIS are to provide core cooling by injecting borated water from the RWST into the core following a LOCA, limit the positive reactivity addition from the resultant reactor coolant cooldown by injecting borated water from the RWST into the core following an MSLB, provide core reflooding during a large break LOCA by injecting borated water from the safety injection accumulators, and provide containment isolation for piping penetrations following a DBE. This system also provides mitigation of other DBAs, such as the control rod ejection accident and the steam generator tube rupture accident.

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

- to provide a reactor coolant pressure boundary
- to achieve and maintain the reactor core subcritical for any mode of normal operation or event
- to introduce emergency negative reactivity to make the reactor subcritical
- to sense process conditions and generate signals for reactor trip or ESFs actuation
- to provide and maintain sufficient reactor coolant inventory for abundant core cooling
- to introduce negative reactivity
- to provide primary containment boundary
- to maintain the dose consequences within the guidelines of 10 CFR 50.67 or 10 CFR 100
- to ensure adequate cooling in the spent fuel pool (SFP) to maintain stored fuel within acceptable temperature limits

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

Additional details of the SISs are provided in the UFSAR Sections 6.3.1, 6.3.2, and 15.6.5.

LRA Table 2.3.2-4, "Safety Injection System," lists the component types that require AMR.

2.3.2.4.2 Staff Evaluation

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

2.3.2.4.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the SIS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SIS components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

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

- LRA Section 2.3.3.1, "Auxiliary Building Ventilation System"
- LRA Section 2.3.3.2, "Chemical & Volume Control System"
- LRA Section 2.3.3.3, "Chilled Water System"
- LRA Section 2.3.3.4, "Circulating Water System"
- LRA Section 2.3.3.5, "Component Cooling System"
- LRA Section 2.3.3.6, "Compressed Air System"
- LRA Section 2.3.3.7, "Containment Ventilation System"
- LRA Section 2.3.3.8, "Control Area Ventilation System"
- LRA Section 2.3.3.9, "Cranes and Hoists"
- LRA Section 2.3.3.10, "Demineralized Water System"
- LRA Section 2.3.3.11, "Emergency Diesel Generator & Auxiliaries System"

- LRA Section 2.3.3.12, “Fire Protection System”
- LRA Section 2.3.3.13, “Fresh Water System”
- LRA Section 2.3.3.14, “Fuel Handling & Fuel Storage”
- LRA Section 2.3.3.15, “Fuel Oil System”
- LRA Section 2.3.3.16, “Heating Water and Heating Steam”
- LRA Section 2.3.3.17, “Non-Radioactive Drain System”
- LRA Section 2.3.3.18, “Radiation Monitoring System”
- LRA Section 2.3.3.19, “Radioactive Drain System”
- LRA Section 2.3.3.20, “Radwaste System”
- LRA Section 2.3.3.21, “Sampling System”
- LRA Section 2.3.3.22, “Service Water System”
- LRA Section 2.3.3.23, “Spent Fuel Cooling System”

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 states the purpose of the auxiliary building ventilation system is to provide filtered, temperature conditioned outside air to the auxiliary building for ventilation, cooling, and heating. The auxiliary building ventilation system also mitigates the spread of contamination following a post-design basis accident by filtering the air through charcoal and high-efficiency particulate air filters. The auxiliary building ventilation system consists of the following plant systems: auxiliary building heating, ventilation, and air conditioning (HVAC); diesel generator (DG) room ventilation; miscellaneous electric equipment room ventilation; switchgear heat removal; radwaste/remote shutdown control room HVAC; machine shop ventilation; laboratory HVAC; containment and auxiliary building filtered vents; containment and auxiliary building non-filtered vents; and radwaste facility ventilation.

The intended functions of the auxiliary building ventilation system within the scope of license renewal include:

- to provide a suitable environment for the operation of the safety-related equipment
- to minimize the spread of radioactivity release or contamination within the Auxiliary Building and Fuel Handling Building and to filter the effluent prior to release to the environment during a post-design basis accident
- to maintain emergency temperature limits and fume removal capability to DG and day tank rooms during DG operations
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49, and SBO (10 CFR 50.63) requirements based on the criteria of 10 CFR 54.4(a)(3)

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

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 and UFSAR Sections 9.4.1, 9.4.2, 9.4.3, 9.4.5, 9.4.7, 11.5.2.2, and Table 3.2-1, and LRA Table 2.3.3-1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.1.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and drawings, the staff concluded that the applicant appropriately identified the Auxiliary Building Ventilation System components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the Auxiliary Building Ventilation System components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Chemical & Volume Control System

2.3.3.2.1 Summary of Technical Information in the Application

The applicant stated that the CVCS is a normally operating, mechanical system designed to control the inventory of the RCS during normal reactor operation. The CVCS consists of four plant systems: CVCS, boric acid processing system, primary water system, and boron thermal regeneration system. The CVCS is within the scope of license renewal.

The chemical addition portion of the system is designed to provide various chemistry functions related to the operation of the RCS, the Spent Fuel Cooling System, and the Radwaste System. In the event the RWST, which is the primary water source for DBAs, is unavailable the boric acid storage tanks and transfer pumps of the chemical addition portion of the system provide the concentrated boric acid needed to achieve cold shutdown.

The CVCS has the following purposes: emergency core cooling, maintain the required RCS inventory, maintain seal water injection flow to the RCPs, control reactor coolant water chemistry conditions, activity level, soluble neutron absorber concentration and makeup, and provide a means of filling, draining, and pressure testing the RCS during shutdown and refueling operations.

The CVCS accomplishes these purposes by providing the necessary tanks, pumps, heat exchangers, demineralizers, filters, piping systems, gas manifolds, and associated valves and controls to perform required functions.

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

- to provide reactor coolant pressure boundary
- to achieve and maintain the reactor core subcritical for any mode of normal operation or event
- to introduce emergency negative reactivity to make the reactor subcritical

- to provide and maintain sufficient reactor coolant inventory for core cooling
- to introduce negative reactivity
- to provide primary containment boundary
- to maintain the dose consequences within the guidelines of 10 CFR 50.67 or 10 CFR 100
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Anticipated Transients Without Scram (10 CFR 50.62)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

Additional details of the CVCS are provided in the UFSAR Sections 6.3.2, 9.3.4, 9.3.4.1, and 9.3.4.2.

LRA Table 2.3.3-2, "Chemical and Volume Control System," lists the component types that require AMR.

2.3.3.2.2 Staff Evaluation

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

2.3.3.2.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the CVCS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the CVCS components subject to an AMR, as required by 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 states the purpose of the chilled water system is to provide cooling water and remove heat from the following loads or buildings during various modes of operation: the control room chilled water subsystem, the containment chilled water subsystem, the auxiliary building chilled water subsystem, and the service building chilled water subsystem. The purposes of the chilled water subsystems include:

- to provide cooling water to the control room ventilation coils to maintain the control room habitable during normal and emergency operations
- to provide cooling water to areas inside the auxiliary building during normal operating conditions to maintain the area temperatures within a suitable range
- to provide cooling water to areas in the radwaste and service building complex, turbine building complex, and auxiliary building during normal operating conditions to maintain the area temperatures within a suitable range
- to provide cooling water to reactor containment fan cooler coils during normal operating conditions to maintain the area temperatures within a suitable range

The intended functions of the chilled water system within the scope of license renewal include:

- to provide heat removal from safety-related equipment.
- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1).
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2).
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

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

2.3.3.3.2 Staff Evaluation

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

2.3.3.3.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the chilled water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the chilled water system components subject to an AMR, as required by 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 states that the purpose of the circulating water system is to remove the majority of the plant heat load. The circulating water system consists of the following plant systems: circulating water and raw water systems including the circulating water makeup and blowdown subsystems. The circulating water then releases this heat to the environment in one of two methods. At Byron Station, heat is transferred to the environment using hyperbolic natural draft cooling towers. At Braidwood Station, heat is transferred to the environment using a cooling lake.

The intended function of the circulating water system at Byron only is to prevent nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2). The circulating water system has the potential for spatial interaction (spray or leakage) with safety-related components in structures that house safety-related components.

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

2.3.3.4.2 Staff Evaluation

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

2.3.3.4.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the circulating water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the circulating water system components subject to an AMR, as required by 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 states that the purpose of the component cooling system is to provide an intermediate cooling loop between heat exchangers that contain radioactive fluid and the service water system for safety-related and nonsafety-related plant loads. By providing a buffer heat sink for heat exchangers that contain radioactive fluid, radioactive leaks can be detected in the component cooling system before any release to the environment.

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

- to provide heat removal from safety-related equipment
- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to provide cooling to the RHR pump seal coolers, the RHR heat exchangers, and other equipment credited for fire safe shutdown in compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

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

2.3.3.5.2 Staff Evaluation

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

2.3.3.5.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the component cooling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the components subject to an AMR, as required by 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 states that 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 and air operated plant and service equipment. The compressed air system consists of the service air system (including the River Screen House service air system), the instrument air system (including the River Screen House instrument air system), the emergency breathing air system, the sparging air system, and portions of the primary containment isolation system.

The intended functions of the compressed air system within the scope of license renewal include:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)

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

2.3.3.6.2 Staff Evaluation

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

2.3.3.6.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the compressed air system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the components subject to an AMR, as required by 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 states the purpose of the containment ventilation system is to cool and dehumidify the containment to provide a suitable operating environment for mechanical, structural, and electrical components; reduce the concentration of fission product activity in the containment atmosphere; supply cool air flow for various components inside the containment structure including the reactor cavity and the magnetic coil windings of the control rod drive mechanisms (CRDMs); dissipate the heat released and limit the containment pressure and temperature following a LOCA; and provide for automatic containment ventilation isolation. The containment ventilation system consists of the following systems: primary containment ventilation system and primary containment purge system. The primary containment ventilation system consists of the following subsystems: the reactor containment fan cooler subsystem, the containment charcoal filter units subsystem, the CRDM ventilation subsystem, and the reactor cavity ventilation subsystem. The primary containment purge system consists of the test connections and piping used during an integrated leak rate test and the following subsystems: miniflow purge subsystem, normal purge subsystem, and post-LOCA purge subsystem.

The intended functions of the containment ventilation system within the scope of license renewal include:

- to provide heat removal from safety-related equipment following a LOCA
- to provide primary containment
- to remove heat and provide pressure control to containment following a LOCA
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)

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

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7; UFSAR Sections 6.2.2, 6.2.4, 6.2.5, 9.4.8, 9.4.9, and E-30; and LRA Table 2.3.3-7 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. During the review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.7.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and drawings, the staff concluded that the applicant appropriately identified the Containment Ventilation System components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the Containment Ventilation System components subject to an AMR, as required by 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 states the purpose of the control area ventilation system is to provide room temperatures, humidity, and habitability of the control room envelope under normal and DBA conditions. The control area ventilation system also maintains the control room at a positive differential pressure relative to the adjacent areas to limit unfiltered inleakage to the control room envelope. The control area ventilation system consists of the control and auxiliary electrical equipment room HVAC plant system.

The intended functions of the control area ventilation system within the scope of license renewal include:

- to provide a habitable temperature and humidity conditions in the control room environment for personnel and safety-related components
- to provide a habitable environment for personnel in the event of a radiological emergency
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

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

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8; UFSAR Sections 6.4, 6.5.1, 7.3.1.1.9, and 9.4.1; and LRA Table 2.3.3-8 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. During the review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.8.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and drawings, the staff concluded that the applicant appropriately identified the Control Area Ventilation System components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the Control Area Ventilation System components subject to an AMR, as required by 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 states that the purpose of the cranes and hoists system is to safely move material and equipment supporting operations and maintenance activities. The cranes and hoists system accomplishes this by compliance with NUREG-0612 and administrative controls so damage from a heavy load drop does not prevent safe shutdown of the reactor.

The intended functions of the cranes and hoists system within the scope of license renewal is to provide a safe means for handling components and loads above or near safety-related components.

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

2.3.3.9.2 Staff Evaluation

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

2.3.3.9.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the cranes and hoists components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 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 states that the purpose of the demineralized water system is to provide a source of high purity, deaerated, demineralized water for the following purposes; condensate makeup, auxiliary steam boiler makeup, primary and secondary process sampling makeup, chemical feed and handling makeup, waste disposal system, reactor coolant makeup, decanting and drumming station, boric acid processing, component cooling, chemical and volume control and boron thermal regeneration, plant chilled water system, and potable water systems.

The intended functions of the demineralized water system within the scope of license renewal are the following:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)

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

2.3.3.10.2 Staff Evaluation

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

2.3.3.10.3 Conclusion

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

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 states that the purpose of the emergency diesel generator (EDG) and auxiliaries system is to provide an independent emergency source of power in the event of a complete loss of offsite power. The DG supplies all of the electrical loads which are required for reactor safe shutdown either with or without a LOCA. The diesel subsystems that support system operation include fuel oil, lubricating oil, combustion air and exhaust, jacket water cooling, starting air, and the pneumatic protection system.

The intended functions of the EDG and auxiliaries system within the scope of license renewal include:

- to provide power to safety-related components
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

LRA Table 2.3.3-11 identifies the EDG and auxiliaries system component types within the scope of license renewal and subject to an AMR.

2.3.3.11.2 Staff Evaluation

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

2.3.3.11.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the EDG and auxiliaries mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant 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 states that the fire protection system consists of fire protection and detection system, halon system, and portions of the carbon dioxide (CO_2) system.

Also included within the scoping boundary of the fire protection system are the physical plant design features that consist of fire barrier walls and slabs, fire barriers, fire doors, fire rated enclosures, and combustible fluid retaining barriers located in structures within the scope of license renewal. The fire protection system is within the scope of license renewal. However, portions of the fire protection system are not required to perform intended functions and are not within the scope of license renewal. The LRA Section 2.3.3.12 states that the RCP oil collection systems are evaluated with the Radioactive Drain System.

LRA Section 2.3.3.12 states that the purpose of the fire protection system is to prevent fires from starting, promptly detect and suppress fires to limit damage, and, in the event of a fire, allow for safe shutdown 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.

LRA Section 2.3.3.12 states that the RCP oil collection systems are not included within the fire protection scoping boundary. The RCP oil collection systems are evaluated with the radioactive drain system.

The intended functions of the fire protection system with the scope of license renewal include the following:

- to support the containment pressure boundary
- to support SFP cooling
- to provide a safety-related backup source of unborated water to the SFP utilizing a cross-tie to the essential service water system
- to resist nonsafety-related SSC failures that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)

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

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 and the relevant LRA drawings using the evaluation methodology described in the SER, Section 2.3, and guidance in SRP-LR, Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff also reviewed the Fire Protection Report which describes the fire protection plans developed for Braidwood Station, Units 1 and 2, and for Byron Station, Units 1 and 2, to comply with the requirements of 10 CFR 50.48 and the guidelines of Branch Technical Position, Chemical Engineering Branch 9.5.1.

The staff also reviewed the following fire protection related documents cited in the CLB listed in the Braidwood Units 1 and 2, Operating License Condition 2.E, Byron Unit 1 Operating License Condition 2.C(6) and Byron Unit 2 Operating License Condition 2.E, respectively.

<u>Braidwood Station, Units 1 and 2</u>

- NUREG-1002, "Safety Evaluation Report Related to the Operation of Braidwood Station, Units 1, and 2," November 1983
- NUREG-1002, Supplement 2, October 1986
- NUREG-1002, Supplement 3, May 1987
- NUREG-1002, Supplement 5, December 1987

<u>Byron Station, Units 1 and 2</u>

- NUREG-0876, "Safety Evaluation Report Related to the Operation of Byron Station, Units 1 and 2," February 1982
- NUREG-0876, Supplement 3, November 1983
- NUREG-0876, Supplement 5, October 1984
- NUREG-0876, Supplement 6, February 1985
- NUREG-0876, Supplement 7, November 1986
- NUREG-0876, Supplement 8, March 1987

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

The staff determined that LRA boundary drawings LRA-BRW-M-52, SH-3, and LRA-BYR-M-52, SH-3, show several fire protection systems/components abandoned in place, including the foam maker chamber at location A6 and fire protection area outdoor fuel oil storage tank fire protection areas IR and IMM at location B6 of boundary drawing LRA-BRW-M-52, SH-3; also the foam maker chamber at location A6 and fire protection area outdoor fuel oil storage tank fire protection areas IR and IMM at location B6 of boundary drawing LRA-BYR-M-52, SH-3.

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

In RAI 2.3.3.12-2, dated November 25, 2013, the staff stated that the LRA did not identify the following fire protection systems/components as being within the scope of license renewal and subject to an AMR:

- filter housing
- passive components in the diesel fuel fire pump
- floor drains for fire water

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

By letter dated December 17, 2013, the applicant responded to RAI 2.3.3.12-2 and stated the following:

> Filter housings: There are no filters in the portion of the Fire Protection System within the scope of license renewal that are subject to aging management review in accordance with 10 CFR 54.21(a)(1). The fire pumps and jockey pumps have suction strainers with a filter intended function. These components are evaluated as component type 'Strainer Element' in LRA Table 3.3.2-12, page 3.3-230, for license renewal aging management review.
>
> Passive components in the diesel-driven fire pump engine: These components are included in the scope of license renewal but are not subject to AMR. The diesel engines include various components necessary to support engine operation. Many of these components are either located internal to the engine or are physically mounted on the engine. These components are considered integral subcomponent parts of the active diesel engine assembly. Table 2.1-5 of NUREG-1800, Revision 2, 'Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants' indicates that the fire pump diesel engines are not subject to aging management review.
>
> Floor drains for fire water: These drains are included in the scope of license renewal and are subject to AMR. As described in LRA Section 2.3.3.19, the Radioactive Drain System includes the drains credited for Fire Protection. The drains are included in LRA AMR Table 3.3.2-19, pages 3.3-272 to 3.3-273, as the piping, piping components, and piping elements component type.

The applicant indicated that filters are not part of the fire protection system. However, fire pumps and jockey pumps have suction strainers with a filter intended function. The applicant stated that it considers this line item under the component type "Strainer Element." The staff confirmed that the suction strainers are included in LRA Table 2.3.3-12 with AMR results in LRA Table 3.3.2-12.

The applicant stated that all subcomponents in the diesel-driven fire pump engine, which are integral to the active diesel engine assembly, are not subject to an AMR. The staff confirmed that these subcomponents are integral to the active diesel engine assembly of the fire pump diesel engines and do not meet the AMR criteria of 10 CFR 54.21(a)(1)(i).

The staff confirmed that the floor drains are included in LRA Section 2.3.3.19, “Radioactive Drain System,” in scoping Table 2.3.3-19 under the component type “piping” with AMR results in LRA Table 3.3.2-19.

LRA Section 2.3.3.12 included walls and slabs credited as fire barriers, fire doors, fire rated enclosures, and combustible fluid retaining barriers located in structures within the scope of license renewal and subject to an AMR. These structures include: the auxiliary building, circulating water pump house (Byron, Units 1 and 2 only), containment structure, fuel handling building, lake screen structures (Braidwood, Units 1 and 2 only), turbine building complex, radwaste and service building complex, and river screen house (Byron, Units 1 and 2 only). In addition, since the earthen berm that surrounds the fuel oil storage tanks prevents the spread of combustible fluid, the function of earthen berm structure is included within the scoping boundary of Section 2.3.3.12. The fire barrier function of all fire damper housings is evaluated with the fire protection system for license renewal AMR. The pressure boundary function of fire damper housings, if applicable, is evaluated with the appropriate ventilation system. These fire barriers components are evaluated in LRA Table 3.3.2-12 for license renewal AMR.

The portion of LRA Section 2.3.3.19, “Radioactive Drain System,” included within the scope of license renewal and subject to an AMR are the RCP oil drip pans, collection piping, oil reservoirs, oil overflow piping, and oil storage vault. The system collects and safely stores lubricating oil from potential RCP leakage sources. The staff confirmed that the RCP oil collection systems and associated components are included in LRA Table 2.3.3-19 as subject to an AMR in LRA 3.3.2-19.

Based on its review, the staff found the applicant’s response to RAI 2.3.3.12-2 acceptable because the applicant provided clarification that the fire protection system and components listed above are within the scope of license renewal and subject to an AMR as required by 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff’s concern described in this RAI is resolved.

In RAI 2.3.3.12-4, dated June 23, 2014, the staff stated that the LRA Section 2.3.3.12 discusses requirements for the fire water supply system but does not mention suction screens for the fire pump suction water supply. The intake traveling screens were not included in the license renewal boundaries; however, they appear to have fire protection intended functions required for compliance with 10 CFR 50.48. Intake traveling screens are located upstream of the fire pump suctions to remove any major debris from the fresh or raw water. Intake traveling screens are necessary to remove debris from and prevent clogging of the fire protection water supply system and have a passive intended function of filter.

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

By letter dated July 18, 2014, the applicant responded to RAI 2.3.3.12-4 and stated that at BBS, the fire pumps are equipped with a stainless steel (SS) suction strainer to protect the pump from debris in the water supply. The fire pump suction strainers are included within the scope of license renewal and are evaluated with the Fire Protection System for an AMR. The fire pump suction strainers are evaluated as component type “Strainer Element” in Table 3.3.2-12 of the LRA. The fire pump suction strainers perform a “Filter” intended function and are managed for aging by the Fire Water System (B.2.1.16) aging management program.

The applicant indicated that the trash racks located in the 1A and 2A Circulating Water Pump House (Byron) intake bays are included within the scope of license renewal and are evaluated with the Circulating Water Pump House (Byron) for an AMR. The trash racks are evaluated as component type “Steel Components (Trash Rack Bars)” in Table 3.5.2-2 of the LRA. The 1A and 2A intake bays at the Circulating Water Pump House (Byron) are not equipped with traveling screens since the water supply is not from an open source where debris from environmental sources is likely.

The applicant also indicated that the trash racks located in the 1A and 2A Lake Screen Structures (Braidwood) intake bays are included within the scope of license renewal and are evaluated with the Lake Screen Structures (Braidwood) for an AMR. The trash racks are evaluated as component type “Steel Components (Trash Rack Bars)” in Table 3.5.2-9 of the LRA. The 1A and 2A intake bays at the Lake Screen Structures (Braidwood) are also equipped with traveling screens. The traveling screens perform the design function specified in National Fire Protection Association (NFPA) 20, “Standard for the Installation of Centrifugal Fire Pumps,” (1983 Edition) by filtering the water entering the 1A and 2A intake bays to remove debris that could potentially degrade the performance of the fire pumps. The applicant stated that the LRA Section 2.3.3.12, Table 2.3.3-12, Table 3.3.1, Table 3.3.2-12, Appendix A, Section A.2.1.16, and Appendix B, Section B.2.1.16, are revised as shown in Enclosure B of letter dated July 18, 2014, to identify the 1A and 2A intake bay traveling screens at Braidwood as within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) and subject to an AMR.

Based on its review, the staff finds the applicant’s response acceptable because it explained that Braidwood traveling screens and BBS trash racks perform filter intended functions. The trash racks and traveling screens are relied upon to perform and support license renewal intended functions. Further, the applicant explained that the intended function supporting the fire pump suction is accomplished with trash racks and traveling screens which are included in the scope of license renewal and subject to an AMR. Additionally, BBS fire pumps are equipped with SS suction strainers to protect the pumps from debris in the water supply and are within the scope of license renewal and subject to an AMR.

At Byron, trash racks prevent debris from reaching the Circulating Water Pump House intake bays (note that Byron Circulating Water Pump House intake bays are not equipped with traveling screens); and at Braidwood, traveling screens and trash racks prevent debris from reaching the Lake Screen Structures intake bays. Therefore, the staff’s concern described in RAI 2.3.3.12-4 is resolved.

2.3.3.12.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, Fire Protection Report, RAI responses, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the fire protection systems and components and fire barrier commodities within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the fire protection systems and components and fire barrier commodities subject to an AMR, as required by 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 states that the purpose of the fresh water system is to supply water in sufficient quantities to satisfy the demand for station potable water, makeup water, safety showers, eye washes, and sanitary water. The license renewal fresh water system consists of the following plant systems: treated water system at Byron and treated water and raw and potable water systems at Braidwood.

The intended function of the fresh water system within the scope of license renewal is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2).

LRA Table 2.3.3-13 identifies the fresh water system component types within the scope of license renewal and subject to an AMR.

2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13, UFSAR Section 9.2.4, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.13.3 Conclusion

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

2.3.3.14 Fuel Handling & Fuel Storage System

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 states that 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, moved into and out of the reactor core, until it leaves the plant after post-irradiation cooling. The fuel handling and fuel storage system controls fuel transfer and storage positions to assure a geometrically safe configuration with respect to criticality, ensure adequate shielding of irradiated fuel for plant personnel to accomplish normal operations, prevent mechanical damage to the fuel during fuel moves, prevent mechanical damage to the stored fuel that could result in a significant release of radioactivity from the fuel, and provide means for the safe handling of new and irradiated fuel.

The intended functions of the fuel handling and fuel storage system within the scope of license renewal include:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to provide protection for safe storage of new and spent fuel
- to ensure adequate cooling in the SFP to maintain stored fuel within acceptable temperature limits
- to prevent criticality of fuel assemblies stored in the SFP
- to resist nonsafety-related SSC failures that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)

LRA Table 2.3.3-14 identifies the fuel handling and fuel storage system component types within the scope of license renewal and subject to an AMR.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14, UFSAR Sections 6.2.6.2.c, 9.1, 9.1.1, 9.1.2, 9.1.4, and 9.1.5, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.14.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the fuel handling and fuel storage system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Fuel Oil System

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 states the purpose of the fuel oil system is to transfer fuel oil to the following systems: the EDG and auxiliaries system, the heating water and heating steam system, the fire protection system, the service water system (Byron only), and the auxiliary feedwater (AFW) system. The fuel oil system consists of the following plant systems: the diesel fuel oil system, the fuel oil system, and the gasoline and diesel oil storage tanks.

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

- to provide power to safety-related components
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in the safety analyses or plant evaluation to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)

LRA Table 2.3.3-15 identifies the fuel oil system component types within the scope of license renewal and subject to an AMR.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15, UFSAR Sections 8.3.1.1.2, 9.2.1.2, 9.2.5.2.2, 9.5.1, 9.5.4, 10.4.9, and 15.2.7, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.15.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the RCS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RCS components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.16 Heating Water and Heating Steam System

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 states that the purpose of the heating water and heating steam system is to provide a source of low pressure, non-contaminated steam for various startup and plant service functions. The auxiliary steam system consists of a Unit 1 and Unit 2 train. The heating water and heating steam system consists of two plant systems which are the auxiliary steam and station heating.

The intended function of the heating water and heating steam systems within the scope of license renewal is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2).

LRA Table 2.3.3-16 identifies the heating water and heating steam system component types within the scope of license renewal and subject to an AMR.

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16, UFSAR Sections 3.6.1, 3.6.2, 3.11.10, 9.2.8 and Table 3.6-2, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

On license renewal boundary drawings LR-BYR-M-65 Sheets 3 and 6 (C1) and LR-BRW-M-65 Sheets 3 and 6 (C1), the staff could not locate seismic anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines 0AS35AB 2 and 0AS35AA 2, respectively, continued from M-56 Sheet 4A (E6/E8) to safety-related valve BEF-40 on LR-BYR/BRW-M-65 Sheets 3 and 6 (D5). By letter dated February 10, 2014, the staff issued RAI 2.3.3.16-1, requesting that the applicant provide additional information on the location of the seismic or equivalent anchor between the safety/nonsafety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response letter, dated February 28, 2014, the applicant provided the location of equivalent anchors between the safety-related to nonsafety-related class change and safety-related valves BEF-40 on license renewal drawings LRA-BYR/BRW-M-56 Sheet 4A. The applicant stated that the piping encompassing the equivalent anchor is within the scope of license renewal per the criterion of 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.16-1 acceptable because the applicant provided the location of equivalent anchors. Therefore, the staff's concern described in RAI 2.3.3.16-1 is resolved.

2.3.3.16.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant 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). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.17 Nonradioactive Drain System

2.3.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 states the non-radioactive drain system consists of five (5) plant systems: miscellaneous drains system, oil drain disposal system, turbine building floor drains system, turbine building equipment drains system, and waste water treatment system. The purposes of the non-radioactive drain plant subsystems include:

- to collect equipment leakage in the form of water generated in the circulating water pump house (Byron only), lake screen house (Braidwood only), river screen house, turbine building complex, waste treatment building, and other yard structures
- to collect water and oil in the turbine building complex and auxiliary building areas that contain equipment that stores and consumes fuel and lubricating oil
- to collect equipment leakage generated in the turbine building complex and in the auxiliary building essential service water sumps
- to recover condensate grade water generated in the turbine building complex
- to process fluids collected in the turbine building fire and oil sump by removing oil and other impurities so that the resulting effluent can be released to the environment

The intended function of the non-radioactive drain system within the scope of license renewal is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2). LRA Table 2.3.3-17 identifies the non-radioactive drain system component types within the scope of license renewal and subject to an AMR.

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, UFSAR Section 11.2, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.17.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified non-radioactive drain system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.18 Radiation Monitoring System

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 states the radiation monitoring system consists of two (2) plant systems: the process radiation monitoring system and the area radiation monitoring system. The purpose of these radiation monitoring systems include:

- to provide primary containment boundary to assure that radioactive material is not inadvertently transferred out of containment

- to monitor for radioactive contamination entering the control area ventilation system
- to monitor for radioactive contamination in the effluent of the auxiliary building vent stack during accident conditions
- to provide for the measurement, indication, and control of radioactive contamination in those streams which discharge outside the plant boundaries
- to provide operating personnel with radiological measurements within plant process systems
- to detect, indicate, and record area radiation levels, annunciate, and provide appropriate interlock signals

The intended functions of the radiation monitoring system within the scope of license renewal include:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to sense process conditions and generate signals for reactor trip or ESFs actuation
- to maintain the dose consequences within the guidelines of 10 CFR 50.67 or 10 CFR 100 during an auxiliary building vent stack radiation discharges, a drop fuel rod accident condition, or a steam generator tube rupture event
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Equipment Qualification (10 CFR 50.49)

LRA Table 2.3.3-18 identifies the radiation monitoring system component types within the scope of license renewal and subject to an AMR.

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18, UFSAR Sections 9.4.1, 9.4.8, 9.4.9, 11.5.1, 12.2.2, 12.3.4, and Appendix E, Section E-30, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). On the basis of its review, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noticed that the license renewal boundary drawing LR-BYR-M-78 Sheet 7 (C8 and D5) has in-scope continuations to M-44 Sheet 3C. Drawing M-44 Sheet 3C was not provided with the LRA. By letter dated February 10, 2014, the staff issued RAI 2.3.3.18-1, requesting that the applicant provide sufficient information to locate the license renewal boundary. The staff also requested that if the continuation cannot be shown on license renewal boundary drawings, then the applicant should provide additional information describing the extent of the scoping boundary and verify whether or not there are additional component types subject to an

AMR between the continuation and the termination of the scoping boundary. Lastly, the staff requested that the applicant provide additional information to clarify the change in scoping classification if the scoping classification of a section of the piping changes over the continuation.

In its response letter, dated February 28, 2014, the applicant stated the table on M-44 Sheet 3C shows 0RE-PR010 (b) as within scope for 10 CFR 54.4(a)(2. The applicant also stated that the “station blowdown” radiation monitor is not within the scope of license renewal and should not be highlighted as within the scope of license renewal. The drawing shows schematic representations of two types of monitoring skids used at Byron labeled as “Detail A” and “Detail B” and are highlighted to show what subcomponents would be included within the scope of license renewal for a typical in-scope monitor. The “Detail A” drawing shows the subcomponents and continuation details associated with the “station blowdown” radiation monitor. Since the “station blowdown” radiation monitor is not within the scope of license renewal, the interfacing drawing, M-44, sheet 3C, was not provided as a boundary drawing.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.18-1 acceptable because the applicant stated 0RE-PR010 (b) is not within the scope of license renewal and explained the application of the table on M-44 Sheet 3C and why M-44 Sheet 3C is not a license renewal drawing. Therefore, the staff’s concern described in RAI 2.3.3.18-1 is resolved.

The staff noticed that on license renewal drawing LR-BRW-M-78 Sheet 6 (C4), the continuation of piping within the scope of license renewal was not provided for the continuation of line 1PR23B 2. By letter dated February 10, 2014, the staff issued RAI 2.3.3.18-2 requesting that the applicant provide additional information to locate the license renewal boundary. The RAI further requested that the applicant provide additional information describing the extent of the scoping boundary and verify whether or not there are additional component types subject to an AMR between the continuation and the termination of the scoping boundary if the continuation cannot be shown on license renewal boundary drawings. Lastly, the staff requested the applicant provide additional information to clarify the change in scoping classification if the scoping classification of a section of the piping changes over the continuation.

In its response letter, dated February 28, 2014, the applicant stated that piping line 1PR23B2 and line 1PR22A are short lengths of piping that extend into the containment air space and are open-ended. The applicant also stated that the arrow shown is used to denote the direction of air flow through the sampler.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.18-2 acceptable because the applicant stated piping line 1PR23B2 and line 1PR22A are short lengths of piping that extend into the containment air space, are open-ended and are not continuations. Therefore, the staff’s concern described in RAI 2.3.3.18-2 is resolved.

The staff noticed that license renewal drawing LR-BRW-M-78 Sheet 6 (A5) shows nonsafety-related outlet line number 1PR23B 2 highlighted to indicate it is in scope for 10 CFR 54.4(a)(1). However, at location (C4), this line is highlighted indicating the line is in scope for 10 CFR 54.4(a)(2). By letter dated February 10, 2014, the staff issued RAI 2.3.3.18-3 requesting that the applicant clarify the scoping classification of line 1PR23B 2.

In its response letter, dated February 28, 2014, the applicant stated license renewal drawing LR-BRW-M-78, sheet 6, correctly shows nonsafety-related outlet piping line number 1PR23B 2 highlighted indicating the line is in scope for 10 CFR 54.4(a)(2). The associated table incorrectly shows this line number highlighted, indicating it is in scope for 10 CFR 54.4(a)(1). In addition to line number 1PR23B the applicant found other discrepancies in the table and stated the table on LR-BRW-M-78, sheet 6. The following piping line numbers in the table are in scope for 10 CFR 54.4(a)(2): 1PR22B2, 2PR22B2, 1PR24B2, 2PR24B2, 1PR23B2, 2PR23B2, 1PR25B2, 2PR25B2.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.18-3 acceptable because the applicant clarified the scoping classification of pipe line 1PR23B 2 as well as other pipe lines that the applicant found to be miss classified. Therefore, the staff's concern described in RAI 2.3.3.18-3 is resolved.

2.3.3.18.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, RAI responses, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the radiation monitoring system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Radioactive Drain System

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 states that the purpose of the radioactive drain system is to collect and analyze drainage from equipment and floor drains in the containment structure, auxiliary building, and fuel handling building. The radioactive drain system consists of the following plant systems: the leak detection system; reactor building and containment equipment drains system; reactor building and containment floor drains system, auxiliary building equipment drain radwaste system; auxiliary building floor drain radwaste system; laundry and floor drains system; laundry equipment/floor drain radwaste system; and chemical radwaste disposal system.

The intended functions of the radioactive drain system within the scope of license renewal are:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in the safety analyses or plant evaluation to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)

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

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19, UFSAR Sections 9.3.3, 9.4.7.2.2, 11.2.2.2, and 6.2.4, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). On the basis of its review, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noticed that on license renewal boundary drawing LR-BRW-M-64 Sheet 4A (B7), lines 1WEC4A and 1WEC2A are shown with an F.4.d symbol indicating nonsafety-related piping runs are connected at both ends to safety-related piping. The continuation to LR-BRW-M-48 Sheet 29 (B7) does not connect to safety-related piping. By letter dated February 10, 2014, the staff issued RAI 2.3.3.19-1 requesting that the applicant provide justification for the F.4.d symbols on LR-BRW-M-64 Sheet 4A.

In its response letter, dated February 28, 2014, the applicant stated that (1) the "F.4.d" symbols from piping lines 1WEC4A 2 and 1WEC2A 2 and LR-BRW-M-48, sheet 29, are incorrectly included on the drawing, and (2) the floor acts as the seismic anchor for the attached safety-related piping.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-1 acceptable because the applicant stated that these symbols were incorrectly placed on the drawings and the floor acts as the seismic anchors for piping lines 1WEC4A 2 and 1WEC2A 2. Therefore, the staff's concern described in RAI 2.3.3.19-1 is resolved.

The staff noticed that on license renewal drawing LR-BRW-M-138 Sheet 4B (A/B7) lines 2WEC4A and 2WEC2A downstream of valves 2CV010A and 2CV010B are shown with an F.4.d symbol indicating nonsafety-related piping runs are connected at both ends to safety-related piping. The continuations to LR-BRW-48 Sheet 29 (B5) do not connect to safety-related piping. By letter dated February 10, 2014, the staff issued RAI 2.3.3.19-2, requesting that the applicant provide justification for the F.4.d symbol on LR-BRW-M-138 Sheet 4B.

In its response letter, dated February 28, 2014, the applicant stated that the "F.4.d" symbol is incorrectly shown. The application also stated that the piping is seismically anchored in the concrete floor and that the floor acts as the structural support.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-2 acceptable because the applicant stated these symbols were incorrectly placed on the drawings and the floor acts as the seismic anchor for piping lines 2WEC4A 2 and 2WEC2A 2. Therefore, the staff's concern described in RAI 2.3.3.19-2 is resolved.

2.3.3.19.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, RAI responses, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the radioactive drain system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.20 Radwaste System

2.3.3.20.1 Summary of Technical Information in the Application

LRA Section 2.3.3.20 states the radwaste system consists of seven (7) plant systems: the radioactive waste gas system, the solid radwaste disposal system, the nitrogen system, the bottled gas system, the volume reduction system, the acid feed and handling system, and the caustic handling system. The purposes of the seven (7) plant systems which make up the radwaste system include:

- to collect, store, and process radioactive gaseous waste from the CVCS, radioactive drain system, radwaste system, RCS, and the sampling system and to have adequate capacity, redundancy, and monitoring capability to meet gaseous discharge concentration limits during periods of design basis fuel leakage
- to receive, concentrate, solidify, package, handle, and provide temporary storage facilities for radioactive wet solid wastes and to collect, monitor, and recycle or release, all potentially radioactive liquid wastes generated at the station during normal operation and maintenance, as well as transient conditions
- to supply nitrogen to plant equipment
- to supply helium, argon, CO_2, and methane to process analysis and laboratory equipment
- to reduce the amount of solid radioactive waste
- to supply sulfuric acid to the steam generator system blowdown and radwaste system mixed bed demineralizers
- to supply caustic acid to the steam generator system blowdown and radwaste system mixed bed demineralizers

The intended functions of the radwaste system within the scope of license renewal are to:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to maintain the dose consequences within the guidelines of 10 CFR 50.67 or 10 CFR 100
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)

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

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20, UFSAR Sections 6.2.6.2, 11.2, 11.3 and 11.4, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). On the basis of its review, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results.

On license renewal boundary drawing LR-BYR-M-69 sheet 1 (E2, E3, E4, E6, E7, and E8), the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines 0GW04AA, 0GW04AB, 0GW04AC, 0GW04AD, 0GW04AE, and 0GW04AF, all of which are continued from M-69 Sheet 2 (D4) to safety-related valves 0GW9297A, 0GW9297B, 0GW9297C, 0GW9297D, 0GW9297E, and 0GW9297F, respectively. By letter dated February 10, 2014, the staff issued RAI 2.3.3.20-1, requesting that the applicant provide additional information to locate the seismic or equivalent anchors between the safety/nonsafety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response letter, dated February 28, 2014, the applicant stated that an anchor is located on line 0GW09D 2 where the line turns from in scope for 10 CFR 54.4(a)(2) to out of scope.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-1 acceptable because the applicant identified the location of the anchor on line 0GW09D 2. Therefore, the staff's concern described in RAI 2.3.3.20-1 is resolved.

The staff noticed on license renewal drawing LR-BRW-M-48 sheet 31 (C1) nonsafety-related line number 0AC07A 1 connected twice to the in-scope sulfuric acid day tank as not highlighted, indicating it is not within the scope of license renewal. Note that on LR-BYR-M-48 sheet 31 (C1), this line is in scope for 10 CFR 54.4(a)(2). By letter dated February 10, 2014, the staff issued RAI 2.3.3.20-2, requesting that the applicant clarify the scoping classification of line 0AC07A 1 on LR-BRW-M-48 Sheet 31.

In its response letter, dated February 28, 2014, the applicant stated piping line 0AC07A 1 is incorrectly shown on LR-BRW-M-48, sheet 31, as being connected to the in-scope sulfuric acid day tank twice, resulting in piping line 0AC07A 1 being shown as not within the scope of license renewal. The applicant stated piping line 0AC07A 1 and the associated breather vent are in scope for 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-2 acceptable because the applicant explained that piping line 0AC07A was incorrectly shown on LR-BRW-M-48, sheet 31. Line 0AC07A 1 and the associated breather vent are within the scope of license renewal for 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.20-2 is resolved.

As to license renewal drawing LR-BRW-M-69 sheet 1 (E2, E3, E4, E6, E7, and E8), the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines 0GW04AA, 0GW04AB, 0GW04AC, 0GW04AD, 0GW04AE, and 0GW04AF all of which are continued from M-69 Sheet 2A (E2) to safety-related valves 0GW9297A, 0GW9297B, 0GW9297C, 0GW9297D, 0GW9297E, and 0GW9297F, respectively. By letter dated February 10, 2014, the staff issued RAI 2.3.3.20-3, requesting that the applicant provide additional information to locate the seismic or equivalent anchors between the safety/nonsafety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

In its response letter, dated February 28, 2014, the applicant stated that there is an anchor located on line 0GW09D 2 where the line turns from in scope for 10 CFR 54.4(a)(2) to out of scope.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-3 acceptable because the applicant stated that there is an anchor on line 0GW09D 2 where the line turns from in scope for 10 CFR 54.4(a) to out of scope. Therefore, the staff's concern described in RAI 2.3.3.20-3 is resolved.

2.3.3.20.3 Conclusion

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

2.3.3.21 Sampling System

2.3.3.21.1 Summary of Technical Information in the Application

LRA Section 2.3.3.21 states the purpose of the primary sampling and secondary sampling systems which make up the sampling system are as follows:

- to provide a means to obtain liquid and gas samples, to provide in-line or laboratory analysis, to analyze for chemical and radiochemical conditions, and to monitor post-accident hydrogen gas concentrations in containment
- to continuously monitor secondary plant chemistry and detect steam generator tube leaks under conditions ranging from full power operation to cold shutdown

The license renewal intended functions of the sampling system are to provide primary containment isolation and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The sampling system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49).

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

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.21, UFSAR Sections 6.2.5.2.2 and 9.3.2, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.21.3 Conclusion

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

2.3.3.22 Service Water System

2.3.3.22.1 Summary of Technical Information in the Application

LRA Section 2.3.3.22 states the purpose of the service water system (essential service water portion) is to provide cooling water to safety-related components and equipment essential to the safe shutdown of the reactor and transfer heat back to the ultimate heat sink (UHS). The main difference between the service water systems at the two sites is the source of water for essential and non-essential service water. The service water system consists of five plant systems: essential service water system, non-essential service water system, screen wash system (Braidwood only), lake cooling (Braidwood only), and portions of the chemical feed and handling system. The service water system also provides cooling for the reactor containment fan coolers to remove heat from the containment structure during normal and accident conditions. The essential service water portion of the service water system also provides a safety-related, backup source of water to the AFW pumps in the event that the condensate storage tank (CST) is not available and provides a source of water to the fire protection system in the event of a loss of the fire protection pumps. Essential service water also provides a safety-related makeup source of water to the component cooling system, and provides a safety-related SFP makeup through the fire protection system.

The license renewal intended functions of the service water system are as follows:

- to provide heat removal from safety-related equipment
- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to provide secondary heat sink
- to provide heat removal for primary containment and provide primary containment pressure control
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)

- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

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

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22, UFSAR Sections 2.3.2.2, 2.4.1.1, 6.2.2.1, 9.2.1, 9.2.1.1, 9.2.1.2, and 9.2.5, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.22.3 Conclusion

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

2.3.3.23 Spent Fuel Cooling System

2.3.3.23.1 Summary of Technical Information in the Application

LRA Section 2.3.3.23 states the spent fuel cooling system consists of the fuel pool cooling and cleanup system including the following three loops: the pool cooling loop, the purification loop, and the skimmer loop. The spent fuel cooling system is common to both units. The purposes of the spent fuel cooling system include:

- to remove decay heat from the SFP
- to purify SFP water
- to clarify SFP water by removing particles floating on the surface of the water

The license renewal intended functions of the spent fuel cooling system are as follows:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to ensure adequate cooling in the SFP to maintain stored fuel within acceptable temperature limits

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)

LRA Table 2.3.3-23 identifies the spent fuel cooling system component types within the scope of license renewal and subject to an AMR.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.23, UFSAR Sections 6.2.1, 9.1.2, and 9.1.3, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.23.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the spent fuel cooling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion System

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:

- LRA Section 2.3.4.1, “Auxiliary Feedwater System”
- LRA Section 2.3.4.2, “Condensate and Feedwater Auxiliaries System”
- LRA Section 2.3.4.3, “Main Condensate and Feedwater System”
- LRA Section 2.3.4.4, “Main Steam System”
- LRA Section 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 states that the purpose of the AFW system is to remove decay heat from the RCS by providing cooling water to the secondary side of the steam generators under normal, shutdown, and accident conditions.

The intended functions of the AFW system within the scope of license renewal are:

- to remove residual heat from the RCS
- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)

- to provide secondary heat sink
- to provide heat removal from safety-related equipment
- to provide power to safety-related components
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Anticipated Transients Without Scram (10 CFR 50.62)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

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

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1, UFSAR Sections 7.3.1.1.6, 7.7.1.21, 9.2.6, 10.4.9, 15.2.6, 15.2.7, 15.2.8, and Attachment 10.D, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.1.3 Conclusion

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

2.3.4.2 Condensate and Feedwater Auxiliaries System

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 states the purpose of the condensate and feedwater auxiliaries system is to allow for greater thermal efficiency of the overall heat cycle, maintain secondary water chemistry as well as the raw water system chemistry to minimize corrosion and biological fouling through chemistry controls, and to supply gland sealing water to the system pumps and valves.

The intended function of the condensate and feedwater auxiliaries system for license renewal is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2).

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

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Sections 10.2.2, 10.3.5, 10.4.6, and 10.4.7, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noticed that license renewal boundary drawing LR-BYR-M-41 Sheet 3 (E5) shows a "TSI" label to indicate the (a)(2) spatial interaction termination for lines 1HD32BB 14 and 1HD32BD 14. However for Unit 2 drawing LR-BYR-M-125 Sheet 3B (C/D-4) staff could not locate the "TSI" labels to show the (a)(2) spatial interaction termination for similar lines 2HD32BB 14 and 2HD32BD 14. By letter dated April 10, 2014, the staff issued RAI 2.3.4.2-1, requesting that the applicant provide additional information to clarify the 10 CFR 54.4(a)(2) spatial interaction termination for lines 2HD32BB 14 and 2HD32BD 14.

In its response letter, dated May 12, 2014, the applicant stated in the early stages of boundary drawing development, notes were used to identify turbine spatial interaction end points, and LR-BYR-M-125, sheet 3B, uses a "Note 3" to identify the termination point. The applicant stated that in order to align to the established turbine spatial interaction nomenclature, "TSI" labels will be placed on drawing LR-BYR-M-125, sheet 3B, and "Note 3" will be removed from the drawing. Additionally, the applicant identified that "TSI" labels were not shown for piping lines 2CDF6AA 1, 2CDF6AB 1, and 2CDF5AB 1 that are connected to either 2HD32BB 14 or 2HD32BD 14 on drawing LR-BYR-M-125, sheet 3B. Also, the applicant stated that the piping lines 2CDF6AA 1 and 2CDF6AB 1, including valves 2CD178A and 2CD178B, were inadvertently not shown in scope for 10 CFR 54.4(a)(2). To correct these discrepancies, the applicant identified piping lines 2CDF6AA 1 and 2CDF6AB 1 as in scope for 10 CFR 54.4(a)(2) up to and including isolation valves 2CD178A and 2CD178B, respectively, and piping line 2CDF5AB 1 will remain not within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-1 acceptable because the applicant explained that in the early stages of boundary drawing development, notes were used to identify turbine spatial interaction end points, TSI labels were used later to simplify the process. The applicant also identified additional errors, which have been corrected. Therefore, the staff's concern described in RAI 2.3.4.2-1 is resolved.

2.3.4.2.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the condensate and feedwater auxiliaries system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.3 Main Condensate and Feedwater System

2.3.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 states the purpose of the main condensate and feedwater system is to provide feedwater from the condenser to the steam generators and maintain the water level in each steam generator within a specific range under all normal operating conditions. It also has the purpose to isolate the flow of feedwater under specific conditions and provide a flow path for the AFW system.

The intended functions of the main condensate and feedwater system within the scope of license renewal are:

- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to provide a secondary heat sink
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

LRA Table 2.3.4-3 identifies the main condensate and feedwater system component types within the scope of license renewal and subject to an AMR.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, UFSAR Section 10.4, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.3.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the main condensate and feedwater system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 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 states the purpose of the main steam system is to provide a containment pressure boundary, remove residual heat from the reactor coolant, and serve as a steam distribution system.

The intended functions of the main steam system within the scope of license renewal are:

- to sense process conditions and generate signals for containment isolation
- to remove residual heat from the RCS
- to provide primary containment boundary in accordance with 10 CFR 54.4(a)(1)
- to provide secondary heat sink
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Fire Protection (10 CFR 50.48)
- relied upon in the safety analysis or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Environmental Qualification (10 CFR 50.49)
- relied upon in the safety analysis or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Anticipated Transients Without Scram (10 CFR 50.62)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63)

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

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4, UFSAR Sections 1.2.2, 5.4.4, 10.3, 10.3.1, 10.3.2, 10.3.3, and 15.1.5, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). On the basis of its review, the staff identified areas in which additional information was necessary to complete the review of the applicant’s scoping and screening results.

The staff noticed that license renewal boundary drawing LR-BYR-M-35 Sheet 3 (C5) shows several lines, including line 1M502EE 8, to be in scope for 10 CFR 54.4(a)(2). However, a portion of line 1M502EE 8 upstream of valve 1WG17DH ¾ is shown as not within the scope of license renewal. By letter dated April 10, 2014, the staff issued RAI 2.3.4.4-1, requesting that the applicant provide additional information to clarify the scoping classification of line 1M502EE 8 upstream of valve 1WG17DH ¾.

In its response letter, dated May 12, 2014, the applicant stated all of the steam dump lines, including the piping line segment 1M502EE 8 upstream of valve 1WG17DH ¾, are within the scope of license renewal due to spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.4-1 acceptable because the applicant stated the portion of line 1M502EE 8 upstream of valve 1WG17DH ¾ is in scope for 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.4-1 is resolved.

2.3.4.4.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the main steam system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 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 states the main turbine and auxiliaries system consists of the main turbine, the moisture separator reheater, and the following plant systems: turbine electrohydraulic control, cold reheat steam, hot reheat steam, extraction steam, turbine gland seal steam, turbine oil, bearing oil transfer and purification, turbine drains, and turbine generator auxiliaries and miscellaneous devices. The purposes of the main turbine and auxiliaries system include:

- to provide motive force for the main generator to generate electrical power for use on the system grid
- to convert thermal energy of the main steam system into mechanical energy to drive the main generator
- to control turbine valve movement, which in turn controls main steam flow at the inlet to the main turbine and provides trip functions for the main turbine and provides a trip signal to the ESFs plant system
- to remove moisture and to reheat exhausted steam from the outlet of the high pressure turbine and supply it to the low pressure turbine to increase cycle efficiency
- to increase the enthalpy of the feedwater being supplied to the steam generators

- to seal the annular openings where the main turbine and steam generator feed pump turbine shafts emerge from their casings, preventing steam leakage and air intrusion along the shaft and also to seal turbine valve stems
- to provide an oil supply to the turbine and generator bearings for lubrication and cooling
- to store and transfer both clean and dirty lube oil
- to collect condensation from each of the main steam lines, gland sealing steam lines, and steam generator feed pump turbines and direct it to the main condenser
- to protect the turbine by actuating trips causing closure of all turbine steam admission valves

The intended functions of the main turbine and auxiliaries system within the scope of license renewal are:

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with 10 CFR 54.4(a)(2)
- relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for Anticipated Transients Without Scram (10 CFR 50.62)

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5, UFSAR Sections 7.7.1.21, 10.1, 10.2, 10.4.3, and 10.4.4, as well as the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.5.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the main turbine and auxiliaries system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 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 containments, structures, and component supports evaluated as a commodity. Specifically, this section describes the following SCs:

- auxiliary building
- circulating water pump house (Byron)
- components supports commodity group

- containment structure
- deep well enclosures (Byron)
- essential service cooling pond (Braidwood)
- essential service water cooling towers (Byron)
- fuel handling building
- lake screen structures (Braidwood)
- main steam & AFW tunnels and isolated valve rooms
- natural draft cooling towers (Byron)
- RWST foundation and tunnel
- radwaste and service building complex
- river screenhouse (Byron)
- structural commodity group
- switchyard structures
- turbine building complex
- yard structures

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 carried out its methodology, the staff's review focused on the implementation results. This focus allowed the staff to confirm that the applicant did not omit any SCs that meet the scoping criteria and are subject to an AMR.

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

In its scoping evaluation, the staff reviewed the applicable LRA sections, focusing on components that the applicant did not include as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR and applicable license renewal boundary drawings, for each structure to determine whether the applicant omitted any components from the scope of license renewal components with intended functions delineated under 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all intended functions delineated under 10 CFR 54.4(a). After the review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine if the functions were performed with moving parts or a change in configuration or properties or if the SCs are subject to replacement after a qualified life or specified period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.1 Auxiliary Building

2.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1, the applicant described the Auxiliary Building at BBS, Units 1 and 2, as a steel and reinforced concrete safety-related structure which includes internal structural components within the scope of license renewal, pursuant to 10 CFR 54.4(a)(1). Portions of the building provide physical support, shelter, and protection for safety-related SSCs and nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function, pursuant to 10 CFR 54.4(a)(2). The Auxiliary Building also provide physical support, shelter, and protection to SSCs that are within the scope of license renewal whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(3) that are relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) requirements. The auxiliary building is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for PTS pursuant to 10 CFR 50.61.

The auxiliary building is a Seismic Category I structure designed to maintain its structural integrity during and following postulated DBAs and extreme environmental conditions. The building is continuous with the safety-related fuel handling building and the nonsafety-related turbine building complex. The main control room is common to both Units 1 and 2 and contains separate control boards at opposite ends of the room. The LRA states that the auxiliary building structure is within the scope of license renewal in its entirety except for cranes, hoists, fire barriers, mechanical and electrical penetrations, diesel exhaust and air intake components, component supports and structural commodities, which are evaluated separately within other buildings, structures and commodity groups of the LRA.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BYR-S-01A and LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff also reviewed LRA Table 2.4-1, which identifies the component types and intended functions of the structure subject to an AMR. Some of the component types include structural bolting, concrete anchors and embedments, concrete, hatches and plugs, masonry interior walls, metal decking, spray shields, and steel elements and components. Intended functions included structural support, missile barrier, high-energy line break (HELB) shielding and water retaining boundary. The AMR results for these components are provided in LRA Table 3.5.2-1.

2.4.1.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Auxiliary Building SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Circulating Water Pump House (Byron)

2.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2, the applicant described the Circulating Water Pump House as a multilevel structure containing various pumps including electric driven fire pumps and nonessential service water pumps. The structure is present at Byron Station, Units 1 and 2, only. The purpose of the structure building is to provide physical support, shelter, and protection for the fire protection equipment and SSCs located within the structure, and relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and 10 CFR 54.4(a)(3). The SSCs associated with the Circulating Water Pump House are all nonsafety-related. The Circulating Water Intake Flume together with the cooling tower basins provides the water volume required to support the fire protection system.

The circulating water pump house structure is located east of the main power block. The below grade portion of the structure is constructed of reinforced concrete founded on bedrock and compacted fill. The above grade exterior walls are comprised of insulated metal siding supported by steel beams, girts and columns, and the roof consists of a built-up roofing system over precast panels supported by beams and columns.

The purpose of the nonsafety-related flume structure is to return water from the cooling tower basins to the pump house.

Included within the boundary of the pump house are structural elements including stop logs, stop log guides, exterior ladders, stairs and metal decking which are not within the scope of license renewal. These nonsafety-related components are provided to facilitate maintenance activities and do not perform a license renewal intended function. The LRA states that outside the circulating water pump house boundary are cranes, hoists, fire barriers, bolting, cable trays, component supports and structural commodities, which are evaluated separately with other systems and commodity groups.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The Circulating Water Pump House at Byron Station is not in scope under 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2) because no portions of the structure are safety-related or relied upon to remain functional during and following DBEs; and failure of nonsafety-related portions of the structure would not prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The structure does meet 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48). LRA Table 2.4-2 identifies the component types subject to an AMR and structure intended functions. Some of the component types include structural bolting, metal decking, structural steel components, hatches and plugs, interior masonry walls, and concrete embedments. The AMR results for these components are provided in Table 3.5.2-2 of the LRA.

2.4.2.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Circulating Water Pump House (Byron only) SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Component Supports Commodity Group

2.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3, the applicant described the Component Supports Commodity Group at BBS, Units 1 and 2, consisting of structural elements and specialty components designed to transfer the load applied from an SSC to the building structural element or directly to the building foundation. Supports include bolted connections, seismic anchors or restraints, constant and variable spring hangers, rod hangers, guides and stops. The group is comprised of supports for American Society of Mechanical Engineers (ASME) Classes 1, 2 and 3, and metal containment (MC) piping and components, cable trays, HVAC ducts, EDGs, platforms, whip restraints, and supports for electrical equipment. Specialty components include snubbers, sliding support bearings and surfaces, vibration isolation elements, and high-strength bolting. Snubbers are also included but, since they are considered active components, are not subject to an AMR except for the end connections which perform a passive function for structural support. The Component Supports Commodity Group includes supports for mechanical, electrical, and instrumentation systems, components, and structures that are within the scope of license renewal; and supports for SSCs which are not within the scope of license renewal but required to restrain or prevent physical interaction with safety-related SSCs (e.g., Seismic II/I). Finally, in response to an issue discovered during the staff's License Renewal Inspection (the 71002 Inspection), the applicant, by letter dated August 29, 2014, added the CRDM seismic support assembly to this group of SSCs. This is discussed in SER Section 3.0.3.2.18, "ASME Section XI, Subsection IWF."

The intended function of Component Supports Commodity Group SCs is to provide structural support or restraint to SSCs in the scope of license renewal pursuant to 10 CFR 54.4(a). The Component Supports Commodity Group also meets NRC regulations to provide physical support, shelter, and protection for SSCs that are relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), pursuant to 10 CFR 54.4(a)(3). The Component Supports Commodity Group SCs are not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for PTS, pursuant to 10 CFR 50.61. Concrete equipment foundations, as well as concrete anchors and concrete embedments, not associated with component supports, are evaluated separately by the applicant elsewhere in the LRA as part of the license renewal structures that contain them.

2.4.3.2 *Staff Evaluation*

The staff reviewed LRA Section 2.4.3 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BYR-S-01A and LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The LRA Table 2.4-3 identifies the component types and intended functions of component supports which are subject to an AMR. Some of the component types include supports for ASME Classes 1, 2, 3, and MC piping and components, expansion and grouted anchors, pipe supports, high-strength bolting for nuclear steam supply system component supports, structural bolting, EDG and HVAC system components, pipe whip restraints, jet impingement shields, platforms, and racks, panels, cabinets and enclosures for electrical equipment. The AMR results for these components are provided in Table 3.5.2-3 of the LRA.

2.4.3.3 *Conclusion*

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Component Supports Commodity Group SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4 Containment Structure

2.4.4.1 *Summary of Technical Information in the Application*

In LRA Section 2.4.4, the applicant described the containment structure at BBS, Units 1 and 2, as a safety-related Seismic Category I structure designed to withstand the effects of DBA loads as applicable, which include the effects of tornado induced wind and missiles, flooding, earthquake, LOCA, and equipment generated missiles. The structure includes the containment buildings, containment internal structures, and exterior structural features. The purpose of the containment structure is to support and protect vital mechanical and electrical equipment, including the reactor vessel, the RCS, the steam generators, pressurizer, and auxiliary and ESFs systems required for safe operation and shutdown of the reactor.

The LRA states that the containment structure is designed to support, shelter and protect safety-related SSCs and components, provide primary containment boundary, control the potential release of fission products to the environment, provide a source of water for ECCS, and provide sufficient air volume to absorb the energy released to the containment in the event of DBEs, pursuant to 10 CFR 54.4(a) (1). The structure also provides physical support and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1), pursuant to 10 CFR 54.4(a)(2), and meets NRC regulations to provide physical support, shelter, and protection for SSCs that are relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), pursuant to 10 CFR 54.4(a)(3). The containment structure is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for PTS, pursuant to 10 CFR 50.61. Not included in the boundary of the containment structure are the polar gantry crane, hoists, RCS and other mechanical systems and components, electrical systems, commodities, fuel handling equipment and fuel transfer tube, component supports, and structural commodities, which are separately evaluated with their respective systems.

2.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BYR-S-01A and LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-4 identifies the components types subject to an AMR and structure intended functions. Some of the component types include structural bolting, concrete, containment liner, hatches and plugs, electrical and I&C assemblies, interior masonry walls, mechanical penetrations, miscellaneous steel, penetration sleeves, pipe whip restraints, prestressing system (tendons), seals, gaskets, and moisture barriers. The AMR results for these components are provided in Table 3.5.2-4 of the LRA.

2.4.4.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the containment structure SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.5 Deep Well Enclosures (Byron)

2.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.5, the applicant described the deep well enclosures as safety-related, Seismic Category I structures constructed of reinforced concrete walls on spread footings with a removable concrete slab top. The enclosures provide shelter and protection for well water system components and are only present at Byron Station. The deep wells and well water system are nonsafety-related and provide an emergency makeup source of water to the essential service water cooling towers and essential service water system in the event that the safety-related makeup water source from the Rock River is not available.

In-scope structural components within the license renewal boundary include reinforced concrete walls, footings and removable slab top, steel casing and grout inside the deep well which provide physical support for maintaining the well configuration, as well as structural bolting, steel vents, and concrete embedments.

Mechanical components, including piping, pumps, and valves, associated with the well water system, are not included within the boundary of the deep well enclosures and are evaluated separately with the demineralized water system; and structural commodities, including their respective bolting, are evaluated with the structural commodity group. The structure intended functions previously discussed are within the scope of license renewal and support both safety-related and nonsafety-related intended functions, pursuant to 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2). The deep well enclosures are not in scope under 10 CFR 54.4(a)(3) because they are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), SBO (10 CFR 50.63), and PTS (10 CFR 50.61).

2.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.5 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-5 identifies the component types subject to an AMR and structure intended functions. Component types include structural bolting, concrete, concrete embedments, and miscellaneous structural steel. The AMR results for these components are provided in Table 3.5.2-5 of the LRA.

2.4.5.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Deep Well Enclosures SCs within the scope of license renewal, as required by 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.6 Essential Service Cooling Pond (Braidwood)

2.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.6, the applicant described the boundary of the Essential Service Cooling Pond as including the Braidwood cooling pond and dike system, the essential service cooling pond, pond makeup structure and fresh water holding pond, and the overflow spillway. The Essential Service Cooling Pond meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following DBEs. The structure also meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of a function identified for 10 CFR 54.4(a)(1).

The Essential Service Cooling Pond, which is only present at Braidwood Station, meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection and SBO, but does not perform a function that demonstrates compliance with NRC regulations for

EQ, PTS, or ATWS. The Essential Service Cooling Pond also provides physical support, shelter, and protection for safety-related SSCs, provides the ultimate heat sink (UHS) during DBEs, and provides a source of cooling water for plant safe shutdown. As previously stated, the Essential Service Cooling Pond boundary includes the following structures:

- *Braidwood Cooling Pond*

  The purpose of the Braidwood Cooling Pond is to provide a source of cooling water for the Circulating Water System and other nonsafety-related cooling systems. The exterior of the pond is surrounded by a nonsafety-related water retaining dike system with soil and riprap embankments that rise to an elevation to prevent flooding of the Braidwood site. The essential service cooling pond area within the Braidwood cooling pond is considered safety-related while the exterior dike system, which provides flood protection for the site, is considered nonsafety-related. The remaining portions of the pond are nonsafety-related and do not perform an intended function for license renewal.

- *Essential Service Cooling Pond*

  The Essential Service Cooling Pond is an excavated area within the cooling pond and provides the UHS for the Braidwood Station and also provides a source of water volume for the fire protection system. The cooling pond is a Category I, safety-related structure required to maintain structural integrity and an adequate volume of cooling water for safety-related systems during DBEs. It is designed to provide an adequate cooling water volume for a minimum of 30 days operation with no makeup in the event the nonsafety-related exterior retaining dikes of the Braidwood cooling pond fail. The earthen structure and embankments of the cooling pond are included within the boundary and determined to be within the scope of license renewal, but the circulating water discharge structure, essential service water discharge structure, and lake screenhouse are not included within the boundary of the cooling pond. These structures are evaluated separately with the Lake Screen Structures.

- *Pond Makeup Structure*

  The Pond Makeup Structure and freshwater holding pond is a reinforced concrete wall that provides physical support for the circulating water makeup pipes that discharge into the freshwater holding pond. The freshwater holding pond is a reinforced concrete and earthen dike structure that allows for settlement of particulates in the makeup water, pumped from the Kankakee River, before entering the cooling pond. The Essential Service Cooling Pond contains a sufficient volume of water without makeup to maintain adequate cooling for a minimum of 30 days, in accordance with RG 1.27. The pond makeup structure and freshwater holding pond are nonsafety-related structures since they do not perform an intended function for license renewal, are not required for safe shutdown, nor are they relied upon in the mitigation of any DBEs.

- *Overflow Spillway*

  The Overflow Spillway passively drains the Braidwood Cooling Pond when the water level becomes sufficiently high to prevent overtopping of the exterior dikes that could potentially flood the power block. The Overflow Spillway is a nonsafety-related structure, however, it is credited as providing drainage of the pond in the determination of the maximum water surface elevation and the controlling event for flooding at Braidwood. Included within the boundary and determined to be within the scope of license renewal are the earthen and riprap elements of the overflow spillway and exterior dike system, which provide flood protection measures for the site during probable maximum flood conditions.

2.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.6 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-6 identifies the component types subject to an AMR and structure intended function. Component types include earthen water-control structures associated with the Essential Service Cooling Pond and the Spillway and Dike System, while intended functions include heat sink, water retaining boundary and flood barrier. The AMR results for these components are provided in Table 3.5.2-6 of the LRA.

2.4.6.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Essential Service Cooling Pond SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7 Essential Service Water Cooling Towers (Byron)

2.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.7, the applicant described the essential service water cooling towers as two four-cell Seismic Category I concrete structures erected over reinforced concrete water basins that are connected by an overflow design feature and separately supported on a 3-foot-thick reinforced concrete mat foundation resting on grouted bedrock. The cooling towers provide the UHS for the safety-related service water system on a normal and an emergency basis. The UHS is also designed to withstand design-basis tornado winds and tornado missiles, with noted exceptions as described in UFSAR Section 9.2.5.3.2. The internal water distribution system and the clay tile fill are supported on a concrete beam and column system with bracing to resist lateral loads. The towers are present at Byron Station, Units 1 and 2, only. The towers provide physical support, shelter, and protection for the safety-related equipment located within the structures. Included within the cooling towers' boundary and determined not to be within the scope of license renewal is the security structure, sodium hypochlorite tanks, and two chemical buildings which are considered nonsafety-related.

The cooling towers meet 10 CFR 54.4(a)(1) because they are safety-related structures that are relied upon to remain functional during and following DBEs; and 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The cooling towers also meet 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), but are not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62).

2.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-7 identifies the component types subject to an AMR and structure intended functions. Component types include structural bolting, concrete, concrete anchors and embedments, structural steel components, hatches and plugs, and support members. Intended functions include structural support, missile and flood barriers, and water retaining boundary. The AMR results for these components are provided in Table 3.5.2-7 of the LRA.

2.4.7.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Byron essential service water cooling towers SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.8 Fuel Handling Building

2.4.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.8, the applicant described the fuel handling building at BBS, Units 1 and 2, as a multi-story, Seismic Category I safety-related structure designed to maintain its structural integrity during and following postulated DBAs and extreme environmental conditions. The boundary of the building includes the adjacent nonsafety-related fuel handling building train shed which is used for access to the fuel handling building. The fuel handling building is a reinforced concrete structure supported by a concrete mat foundation, which at Byron is supported directly on bedrock. At Braidwood, the mat foundation is supported on lean concrete over glacial till and compacted sand. The above grade portion of the building has a structural steel frame with reinforced concrete slabs on metal decking. The building contains a single fuel transfer canal, SFP and cask loading pit, cask decontamination area, and new fuel storage vaults, all of which are shared between Units 1 and 2. The purpose of the fuel building is to provide physical support, shelter, and protection to SSCs during normal plant operation, and during and following postulated DBAs and environmental conditions. The fuel transfer tube, blind flange, and manually operated valve are evaluated with the fuel handling and storage system, while the section of the fuel transfer tube penetration sleeve, which serves as a portion of the containment boundary, is evaluated as part of the containment structure. The components included within the boundary are the miscellaneous SS components inside of the

SFP and fuel transfer canal, as well as structural steel associated with the leak chase system. The entire fuel handling building and adjacent train shed is within the scope of license renewal while the building crane is separately evaluated with cranes and hoists and are not included within the boundary of the fuel building.

Each fuel handling building meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following DBEs; and meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The buildings also meet 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), but are not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62).

2.4.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.8 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BYR-S-01A and LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-8 identifies the component types subject to an AMR and structure intended functions. Component types include structural bolting, concrete, concrete anchors and embedments, structural steel components, hatches and plugs, interior masonry walls, and metal decking. Intended functions include structural support, missile and flood barriers, shielding, and water retaining boundary. The AMR results for these components are provided in Table 3.5.2-8 of the LRA.

2.4.8.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the essential fuel handling building SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the essential fuel handling building SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.9 Lake Screen Structures (Braidwood)

2.4.9.1 Summary of Technical Information in the Application

In LRA Section 2.4.9, the applicant described the purpose of the Lake Screen Structures as providing physical support, shelter, and protection for the pumping equipment for the Circulating Water, nonsafety-related Service Water and fire protection systems that take suction from the cooling lake. The Lake Screen Structures also provide the suction point for the safety-related Service Water system from the essential service cooling pond, which is the UHS for Braidwood Station, Units 1 and 2. The lake screen structures are present at Braidwood Station, Units 1 and 2, only, and include within the boundary the lake screen house, the chemical feed tank building, the foundations for the CO_2 gas tank and chemical storage tanks, the circulating water discharge structure, and the essential service water discharge structure. Portions of the lake screen house (substructure) and the entire essential service water discharge structure are considered safety-related Seismic Category I and relied upon to remain functional during and following DBEs; all other structures are considered nonsafety-related. Other components, structures, and commodities not included within the boundary of the Lake Screen Structures are also in-scope for license renewal, but evaluated separately within their respective license renewal systems (e.g., fire protection, Service Water, circulating water, and condensate and feedwater auxiliaries).

The Lake Screen House houses electric driven fire pumps, nonessential service water pumps, screen wash pumps, traveling screens, instrumentation panels, jib crane hoists, safety-related service water intakes and isolation valves, and an overhead crane. The reinforced concrete structure is supported on a concrete mat foundation resting on natural ground.

The substructure, which houses the safety-related Service Water intakes and valve pits, is designed as a safety-related structure, but SSCs associated with the lake screen house are considered nonsafety-related. The chemical feed tank building adjoins the lake screen house. The concrete foundations for the chemical storage tanks and chemical injection feed equipment are located outside the lake screen house structure; and the concrete foundation for the CO_2 gas tank is located north of the lake screen house. The Circulating Water Discharge Structure provides a point of discharge for the two, 16 foot diameter circulating water pipes that are routed underground from the turbine building.

The essential service water discharge structure is a reinforced concrete safety-related structure founded on a glacial till deposit overlying the Carbondale bedrock formation which is not susceptible to liquefaction. The structure is the discharge point to the UHS and the anchorage for the discharge end of the essential service water pipes in the essential service cooling pond. The Lake Screen Structures at Braidwood meet 10 CFR 54.4(a)(1) because they are safety-related structures that are relied upon to remain functional during and following DBEs; but are not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structures would not prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The structures also meet 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), but are not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62).

2.4.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.9 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-9 identifies the component types subject to an AMR and structure intended functions. Some of the component types included within the boundary of the lake screen structures include structural bolting, concrete embedments and anchors, concrete slabs, structural steel components, interior masonry walls, and hatches and plugs. Intended functions include structural support, shelter, protection, and missile barrier. The AMR results for these components are provided in Table 3.5.2-9 of the LRA.

2.4.9.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Braidwood lake screen structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the Braidwood lake screen structures SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.10 Main Steam & Auxiliary Feedwater Tunnels and Isolated Valve Rooms

2.4.10.1 Summary of Technical Information in the Application

In LRA Section 2.4.10, the applicant described the main steam & AFW tunnels and isolation valve rooms structure at BBS, Units 1 and 2, as a bi-level reinforced concrete box section with the top of the tunnel approximately 1 ft below grade level. The structure contains safety-related cables in conduits, main steam and main condensate and feedwater piping, and reinforced concrete main steam isolation valve (MSIV) rooms adjoining each of the Unit 1 and Unit 2 containment structures. The purpose of the main steam & AFW tunnels and isolation valve rooms is to provide support, shelter, and protection of AFW, main steam, and main condensate and feedwater piping and components, as well as their supporting mechanical and electrical systems. The tunnels are classified as safety-related structures. The isolation valve room is a reinforced concrete structure which is an integral part of the tunnel at the containment building. Included within the boundary of the structure and within the scope of license renewal are reinforced concrete components that make up the structures, as well as blow out panels, flood barriers, and miscellaneous steel components.

Other components not included within the boundary of the structure and considered within the scope of license renewal are structural commodities and bolting, which are evaluated with the structural commodity group, and nonsafety-related MSIV room ventilation components, which are evaluated with the miscellaneous ventilation systems. The main steam & AFW tunnels and isolation valve rooms meet 10 CFR 54.4(a)(1) because the structures are safety-related and relied upon to remain functional during and following DBEs; and also meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structures could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The structures also meet 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), pursuant to 10 CFR 54.4(a)(3), but are not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for PTS, pursuant to 10 CFR 50.61.

2.4.10.2 Staff Evaluation

The staff reviewed LRA Section 2.4.10 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BYR-S-01A and LR-BRW-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-10 identifies the component types subject to an AMR and structure intended functions. Some of the component types include structural bolting, blowout panels, concrete, flood barriers, hatches and plugs, steel components, and pipe whip restraints and jet impingement shields. Intended functions included pressure relief, flood and missile barriers, HELB shielding, structural support, shelter and protection. The AMR results for these components are provided in Table 3.5.2-10 of the LRA.

2.4.10.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the main steam & AFW tunnels and isolation valve rooms SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant has adequately identified the main steam & AFW tunnels and isolation valve rooms SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.11 Natural Draft Cooling Towers (Byron)

2.4.11.1 Summary of Technical Information in the Application

In LRA Section 2.4.11, the applicant described the Natural Draft Cooling Towers which are present at Byron Station, Units 1 and 2, only. The boundary of the towers includes the two cooling towers (one per unit) and their associated cooling tower basins and riser valve buildings. The cooling towers are nonsafety-related structures designed to provide cooling to the circulating water and non-essential service water systems, and are constructed of reinforced concrete and founded on a concrete foundation supported by bedrock and controlled compacted fill. The riser valve buildings are located along the outside perimeter of the cooling tower structures and consist of reinforced concrete slabs and foundation with insulated metal siding and roof supported by a structural steel frame. The cooling tower basins together with the circulating water intake flume also provide the required water for the fire protection system. The remainder of the cooling tower and supporting structures has no safety-related or other license renewal function.

Included within the boundary of the cooling towers and determined to be within the scope of license renewal are the reinforced concrete cooling tower basin slabs, foundations basin walls, and the seals and gaskets used to contain and provide the water source for the fire protection system. The natural draft hyperbolic draft cooling towers, fill, louvers, support columns, riser valve buildings and circulating water piping, basin screens, and other miscellaneous tower components, included within the boundary of the cooling towers, are not in-scope for license renewal. Not included within the boundary are component supports, structural commodities, mechanical components, and the water intake flume, which are evaluated separately for license renewal with their associated systems.

The Natural Draft Cooling Towers are not within the scope of license renewal under 10 CFR 54.4(a)(1) because no portions of the towers are considered safety-related or relied upon to remain functional during and following DBEs; and also are not within the scope of license renewal under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the towers would not prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The towers meet 10 CFR 54.4(a)(3) criteria because the basins of the towers are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), but are not relied upon for SBO (10 CFR 50.63), EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62). The circulating water intake flume together with the cooling water tower basins provides the water required to support the fire protection system.

LRA Table 2.4-11 identifies the component types subject to an AMR and structure intended functions. Component type includes concrete for above and below grade exterior application, while the intended functions include structural support and water retaining boundary. The AMR results for these components are provided in Table 3.5.2-11 of the LRA.

2.4.11.2 Staff Evaluation

The staff reviewed LRA Section 2.4.11 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-11 identifies the component types subject to an AMR and structure intended functions. Component type includes concrete for above and below grade exterior application, while the intended functions include structural support and water retaining boundary. The AMR results for these components are provided in Table 3.5.2-11 of the LRA.

2.4.11.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Byron Natural Draft Cooling Towers SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the Byron Natural Draft Cooling Towers SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.12 Refueling Water Storage Tank Foundation and Tunnel

2.4.12.1 Summary of Technical Information in the Application

In LRA Section 2.4.12, the applicant described the RWST foundation and tunnel at BBS, Units 1 and 2. Each RWST is a reinforced concrete cylindrical tank structure with an SS interior liner supported on a concrete mat that is continuous with the end of the fuel handling building foundation. The RWST tunnels are routed around either side of the fuel handling building and contain piping that runs from each Unit 1 and Unit 2 tank to the auxiliary building; and there are two RWSTs per station. The purpose of the RWST is to provide a source of borated water to the chemical & volume control, safety injection (SI), RHR, containment spray, and spent fuel cooling systems. The foundations provide physical support for the tanks and the tunnels provide shelter and protection for safety-related SI system piping, conduits, and other components routed within. Included within the boundary of the RWST foundation and tunnel and in-scope for license renewal are the access hatches, miscellaneous structural steel, components associated with the tank leak chase, and structural bolting. Platforms and handrails are not within the scope of license renewal since they do not perform an intended function that would impact a safety-related function. Not included within the boundary and in-scope for license renewal are the internal SS liners of the tanks, evaluated separately with the SI system, while component supports and bolting are evaluated with the Component Supports and Structural Commodity Group.

The tanks, foundation, and tunnel structures are in-scope pursuant to 10 CFR 54.4(a)(1) because the structures are safety-related and relied upon to remain functional during and following DBEs; and within the scope of license renewal under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structures could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The structures also meet 10 CFR 54.4(a)(3) criteria because they are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), SBO (10 CFR 50.63), and EQ (10 CFR 50.49); but are not relied upon to perform a function that demonstrates compliance with PTS (10 CFR 50.61) or ATWS (10 CFR 50.62).

2.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.12 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BRW-S-01A and LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-12 identifies the component types subject to an AMR and structure intended functions. Component type includes structural bolting, concrete for above and below grade exterior applications, miscellaneous steel and steel components, while the intended functions include structural support, flood and missile barrier protection. The AMR results for these components are provided in Table 3.5.2-12 of the LRA.

2.4.12.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the RWST Foundation and Tunnel SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RWST Foundation and Tunnel SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.13 Radwaste and Service Building Complex

2.4.13.1 Summary of Technical Information in the Application

In LRA Section 2.4.13, the applicant described the purpose of the Radwaste and Service Building Complex at BBS, Units 1 and 2, as providing physical support, shelter and protection for radioactive solid radwaste treatment facilities, tanks, filters, radwaste cranes and hoists, and radwaste ventilation system. The complex is comprised of the radwaste building, the original service building, the new service building, and the radwaste tunnel. The radwaste building and the original service building comprise a single building structure and is constructed from reinforced concrete and steel founded on a concrete mat foundation that also supports the Turbine Building Complex. The buildings included within the boundary of the Radwaste and Service Building Complex, including the tunnel, are nonsafety-related and do not contain any safety-related SSCs, however portions of the building and tunnel provide a flood barrier (license renewal intended function) for the safety-related equipment located inside of the Auxiliary Building.

The Radwaste and Service Building Complex intended functions are structural support, shelter, protection, and flood barrier support. The flood barrier function is performed by components in the building that include the ground floor slab and walls, and the partial height wall that surrounds the slab opening. The reinforced concrete components and seals of the radwaste tunnel also perform a flood barrier function. The new service building, included within the boundary of the Radwaste and Service Building Complex, is not in-scope for license renewal since it is nonsafety-related and does not contain any safety-related SSCs that perform a safety function under 10 CFR 54.4(a). The Radwaste and Service Building Complex is not within the scope of license renewal under 10 CFR 54.4(a)(1) because no portions of the buildings are safety-related and the buildings do not contain any safety-related SSCs. However, the buildings meet 10 CFR 54.4(a)(2) criteria because failure of the buildings or SSCs inside the buildings would prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The complex is separated from safety-related SSCs and components such that a structural failure would not impact a safety-related function.

The Radwaste and Service Building Complex and the original service building provide physical support, shelter, and protection to portions of the fire protection system and as such, also meet 10 CFR 54.4(a)(3) criteria because they are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48); but are not relied upon to perform a function that demonstrates compliance with EQ (10 CFR 50.49), ATWS (10 CFR 50.62), SBO (10 CFR 50.63), or PTS (10 CFR 50.61).

2.4.13.2 Staff Evaluation

The staff reviewed LRA Section 2.4.13 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BRW-S-01A and LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-13 identifies the component types subject to an AMR and structure intended functions. Component type includes structural bolting, concrete for above and below grade exterior applications and foundations, masonry walls, metal decking and precast panels, while the intended functions include structural support and flood barrier protection. The AMR results for these components are provided in Table 3.5.2-13 of the LRA.

2.4.13.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Radwaste and Service Building Complex SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the Radwaste and Service Building Complex SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.14 River Screen House (Byron)

2.4.14.1 Summary of Technical Information in the Application

In LRA Section 2.4.14, the applicant described the River Screen House (Byron Station, Units 1 and 2, only), as a safety-related Seismic Category I structure which is relied upon for postulated DBEs. The above grade portion of the structure consists of insulated metal siding supported by steel beams, girts, and columns, while the below-grade portion is constructed of reinforced concrete. The purpose of the River Screen House is to provide physical support, shelter, and protection for both the safety-related and nonsafety-related equipment located in the structure. The safety-related equipment includes the diesel driven essential service water makeup pumps and their respective diesel oil storage tanks and associated equipment. The screen house boundary includes the river screen house and the nonsafety-related circulating water blowdown structure. The structure is constructed of reinforced concrete and is used to transfer water from the circulating water blowdown line to the Rock River. The structure is not in-scope for license renewal since it does not perform a license renewal intended function. All SSCs associated with the blowdown structure are nonsafety-related and do not perform any intended safety functions under 10 CFR 54.4(a).

Included within the boundary of the River Screen House and determined not to be within the scope of license renewal are the structural elements outside of the river screen house that include the sediment management components which are nonsafety-related and do not perform a license renewal function. Not included within the boundary of the River Screen House are component supports, cranes and hoists, fire barriers, structural commodities, and mechanical and electrical systems and components, which are evaluated separately with the Component Supports Commodity Group, the Structural Commodity Group, the fire protection system, and the respective mechanical and electrical license renewal systems or commodities. The River Screen House meets 10 CFR 54.4(a)(1) criteria because it is a safety-related structure that is relied upon to remain functional during and following DBEs; and also meets 10 CFR 54.4(a)(2) criteria because failure of nonsafety-related portions of the structures could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The structure also meets 10 CFR 54.4(a)(3) criteria because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), but is not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62).

2.4.14.2 Staff Evaluation

The staff reviewed LRA Section 2.4.14 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plan (LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-14 identifies the component types subject to an AMR and structure intended functions. Some of the component types include structural bolting, concrete anchors and embedments, concrete, concrete block masonry walls, earthen water-control structures, hatches and plugs, metal decking, and steel components. Intended functions include structural support, shelter, flood barrier and protection. The AMR results for these components are provided in Table 3.5.2-14 of the LRA.

2.4.14.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Byron River Screen House SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the Byron River Screen House SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.15 Structural Commodity Group

2.4.15.1 Summary of Technical Information in the Application

In LRA Section 2.4.15, the applicant stated that the Structural Commodity Group at BBS, Units 1 and 2, shares material and environment properties allowing common programs across all in-scope structures to manage their aging effects. Structural Commodities include bird screens, structural bolting, cable trays, compressible joints and seals, conduit, doors, insulation and jacketing, louvers, metal siding, miscellaneous steel, panels, racks, cabinets, penetration seals and sleeves, roofing, seals, gaskets, moisture barriers, and tube track. Structural commodities are located within structures that are within the scope of license renewal.

The Structural Commodity Group meets 10 CFR 54.4(a)(1) because it is a safety-related commodity group that is relied upon to remain functional during and following DBEs; and also meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the commodity group could prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The commodity group also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), SBO (10 CFR 50.63), EQ (10 CFR 50.49), and ATWS (10 CFR 50.62); but is not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for PTS (10 CFR 50.61).

2.4.15.2 Staff Evaluation

The staff reviewed LRA Section 2.4.15 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BRW-S-01A and LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-15 identifies the component types subject to an AMR and structure intended functions. Some of the component types include structural bolting, cable trays, compressible joints and seals, doors, insulation, metal siding, penetration seals and sleeves, miscellaneous steel, roofing, and enclosures. Intended functions include structural support, shelter and protection, flood barrier, HELB shielding, structural pressure barrier, pipe whip restraint, shielding, thermal insulation, and filtering. The AMR results for these components are provided in Table 3.5.2-15 of the LRA.

2.4.15.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the Structural Commodity Group SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the Structural Commodity Group SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.16 Switchyard Structures

2.4.16.1 Summary of Technical Information in the Application

In LRA Section 2.4.16, the applicant described the switchyard structures at BBS, Units 1 and 2, as nonsafety-related structures that are separated from safety-related SSCs such that their failure would not impact a safety-related function. The purpose of the switchyard structures is to provide physical support, shelter, and protection for the Offsite Power System which receives offsite power from independent power sources at both BBS, and is relied upon to provide offsite power during the restoration from an SBO event. The boundary includes the 345-kV switchyard structures, the switchyard relay house, the maintenance building, the intermediate towers from the 345-kV switchyard to the main and system auxiliary transformers (SATs), and the towers at the transformers. The structures included within the scope of license renewal are the switchyard structures, foundations, towers, and steel components that are associated with the in-scope portions of the Offsite Power System, the switchyard relay house, the intermediate towers from the switchyard to the SATs, and the transformer towers at the SATs. The foundations consist of reinforced concrete below grade piers on footings bearing on compacted soil, whereas the switchyard relay house is a single story above grade masonry wall structure with a precast concrete hollow slab covered with built-up roofing.

Included within the boundary but not in-scope for license renewal are the intermediate towers and transformer towers associated with the main transformer, which is not relied upon to provide offsite power during the SBO restoration event. The switchyard maintenance building is also within the boundary and along with the towers is also considered nonsafety-related and not in-scope for license renewal since the building and the towers do not perform an intended function. Other nonsafety-related components and structures which are outside the boundary of the switchyard structures are also not within the scope of license renewal, since they do not support the SBO intended function. Not included within the boundary are the component supports, structural commodities, and auxiliary transformer foundations. The supports and structural commodities are evaluated with the component supports commodity group and the structural commodity group, while the SAT foundations are evaluated with the yard structures. The electrical components and commodities are separately evaluated with the offsite power system. The structure intended functions support only regulated events (fire protection and SBO), pursuant to 10 CFR 54.4(a)(3).

The Switchyard Structures are not within the scope of license renewal under 10 CFR 54.4(a)(1) because no portions of the structures are safety-related or relied upon to remain functional during and following DBEs; and also do not meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structures would not prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The Switchyard Structures meet 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), but are not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62).

2.4.16.2 Staff Evaluation

The staff reviewed LRA Section 2.4.16 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BRW-S-)1A and LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-16 identifies the component types subject to an AMR and structure intended functions. Some component types include structural bolting, concrete, structural steel components, metal siding, concrete anchors and embedments, interior masonry walls, transmission towers, metal decking, hatches and plugs, and equipment supports and foundations. Intended functions include shelter, protection, and structural support. The AMR results for these components are provided in Table 3.5.2-16 of the LRA.

2.4.16.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the switchyard structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant has adequately identified the switchyard structures SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.17 Turbine Building Complex

2.4.17.1 Summary of Technical Information in the Application

In LRA Section 2.4.17, the applicant described the Turbine Building Complex at BBS, Units 1 and 2, as a nonsafety-related structure designed to prevent a building collapse that could affect safety-related SSCs under design basis earthquake conditions and as a result of loads imposed by a design basis tornado; and for the substructure and superstructure, uses the loading and design allowables that were used in safety-related designs.

The Turbine Building Complex provides physical support, shelter, and protection to equipment required for license renewal, and safety-related and nonsafety-related SSCs during normal plant operation, and to provide flood protection, missile protection for components in the adjacent Auxiliary Building. The complex is comprised of the turbine building and heater bay, the makeup demineralizer building, the condensate cleanup and technical support center building, and the auxiliary boiler stacks, and contains certain nonsafety-related electrical and mechanical components that provide input signals and actuation devices for the reactor trip and ESFs actuation systems, such as feedwater isolation. These components are evaluated with the Reactor Protection System and the Main Condensate and Feedwater System. The turbine generator pedestal, constructed from reinforced concrete, is also founded on a concrete mat foundation. Common walls exist between the turbine building and the Radwaste and Service Building Complex and the Auxiliary Building. Foundations for the Radwaste and Service Building Complex and the Auxiliary Building structures are evaluated separately under their respective license renewal structures in SER Section 2.4.13 and 2.4.1, respectively.

The Make-up Demineralizer Building is a steel structure founded on a reinforced concrete structure and provides physical support, shelter, and protection for nonsafety-related portions of the fire protection, Main Condensate and Feedwater, and Demineralized Water Systems. The Condensate Clean-up and Technical Support Center Building provides physical support, shelter, and protection of portions of the fire protection system which are relied upon to demonstrate compliance with NRC regulations for fire protection and portions of the Main Condensate and Feedwater System relied upon to demonstrate compliance for SBO; and provides physical support, shelter, and protection for the nonsafety-related portions of the Condensate Clean-up System, fire protection system, and the Main Condensate and Feedwater System. The technical support center equipment and facilities are not considered safety-related and do not perform any intended safety functions under 10 CFR 54.4(a).

The Auxiliary Boiler Stacks, associated with the Heating Water and Heating Steam System, are classified as nonsafety-related and included within the boundary of the Turbine Building Complex, but are not in-scope for license renewal since failure of the stacks will not prevent the satisfactory accomplishment of an intended safety functions under 10 CFR 54.4(a).

The Turbine Building Complex is not within the scope of license renewal under 10 CFR 54.4(a)(1) because no portions of the structure are safety-related or relied upon to remain functional during and following DBEs; but does meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could not prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The Turbine Building Complex also meets 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), SBO (10 CFR 50.63), and ATWS (10 CFR 50.62); but are not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49) or PTS (10 CFR 50.61).

2.4.17.2 Staff Evaluation

The staff reviewed LRA Section 2.4.17 and the applicable sections from the LRA and UFSAR, including the evaluation methodology described in LRA Section 2.0, the license renewal boundary drawing composite site plans (LR-BRW-S-01A and LR-BYR-S-01A), the guidance in SRP-LR Section 2.4, and Section 3.8.4 of the UFSAR, which identifies structures classified as Seismic Category I, to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-17 identifies the component types subject to an AMR and structure intended functions. Some component types include blowout panels, structural bolting, concrete, metal and steel components, metal decking, concrete anchors and embedments, interior masonry walls, precast panels, windows, hatches and plugs. Intended functions include shelter, flood and missile barrier protection, and structural support. The AMR results for these components are provided in Table 3.5.2-17 of the LRA.

2.4.17.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the turbine building complex SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the turbine building complex SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.18 Yard Structures

2.4.18.1 Summary of Technical Information in the Application

In LRA Section 2.4.18, the applicant described Yard Structures at BBS, Units 1 and 2, which include storage tank foundations, transformer foundations, duct banks, manholes and handholes, valve and instrument vaults, yard drainage catch basins and ditches, and other miscellaneous yard structures. The Yard Structures provide physical support, missile barrier, shelter, and protection for safety-related and nonsafety-related components and commodities including components credited for fire protection and SBO. The tank foundations included within the boundary of the Yard Structures support the CSTs, fuel oil storage tanks, filtered water storage tanks, primary water storage tanks (PWSTs), treated water storage tank (Byron only), blowdown monitor tank (Braidwood only), lime storage tanks, and the radwaste storage tank (Braidwood only). The CSTs, valve vaults, and associated foundations perform a license renewal intended function of physical support, shelter, and protection and are within the scope of license renewal, and are evaluated under the Main Condensate and Feedwater System. The CST foundations are reinforced concrete structures with the floor slab resting on a sand cushion and surrounded by a reinforced concrete ring wall which are under the tank walls. Reinforced concrete valve vaults, rectangular open top box structures with aluminum covers, are part of the tank foundations at BBS. The following tank foundations and dikes do not perform any license renewal intended functions and are not within the scope of license renewal: filtered water and PWSTs; collection, lime storage and drain tanks; radwaste storage tank at Braidwood, acid tank, and fuel oil storage tanks. The RWST foundations are evaluated with the RWST Foundation and Tunnel previously discussed in Section 2.4.12 of this SE.

Transformer foundations for BBS are reinforced concrete slabs on grade and are nonsafety-related and separated from safety-related SSCs. The foundations, which support the fire barrier walls between the transformers, perform a license renewal intended function for structural support and are within the scope of license renewal. The fire barrier walls are evaluated with the fire protection system. Some of the duct banks, manholes, and handholes structures contain cables within the scope of license renewal and required for safety-related SSCs at Byron Station, or for nonsafety-related SSCs required for fire protection and power restoration following an SBO at BBS. These structures perform the license renewal intended functions of support, shelter, and protection.

Other Yard Structures include valve and line enclosures (pits or vaults) which are reinforced concrete box structures located in the yard area and buried below plant grade with a removable cover for personnel access. The valve and line enclosures at Byron include the essential service water instrumentation pit (including the makeup relief valve vaults), the valve enclosures for the CSTs, and the essential service water blowdown line enclosures. For Braidwood, the valve and line enclosures include the essential service water return valve enclosure, and the valve enclosures at the CSTs. These in-scope structures for BBS perform license renewal intended functions of support, missile protection, shelter, and protection. The yard drainage system includes both the storm drain system and normal waste drain system for BBS Yard and Switchyard areas; and miscellaneous yard structures, which include wells, microwave towers, construction runoff pond at Byron, and concrete foundations for structures that have been removed from the site. These nonsafety-related structures do not perform any license renewal intended function, and are separated from safety-related SSCs such that their failure would not impact a safety-related function, therefore these structures are not within the scope of license renewal. Fire barriers, component supports, structural commodities, and the 345-kV switchyards, are not included within the boundary of the Yard Structures and are evaluated separately with the fire protection system, Component Supports Commodity Group, Structural Commodity Group, and Switchyard Structures.

The Yard Structures, as discussed above, are within the scope of license renewal under 10 CFR 54.4(a)(1) because the structures are safety-related structures that are relied upon to remain functional during and following DBEs; but do not meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure would not prevent satisfactory accomplishment of functions identified for 10 CFR 54.4(a)(1). The Yard Structures also meet 10 CFR 54.4(a)(3) because the structures are relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), but are not relied upon in any safety analyses or plant evaluation to perform a function that demonstrates compliance for EQ (10 CFR 50.49), PTS (10 CFR 50.61), or ATWS (10 CFR 50.62).

2.4.18.2 Staff Evaluation

The staff reviewed LRA Section 2.4.18, the UFSAR, the evaluation methodology described in LRA Section 2.4, the license renewal boundary drawing composite site plans (LR-BYR-S-01A and LR-BRW-S-01A), and the guidance in SRP-LR Section 2.4 to verify that the applicant did not omit from the scope of license renewal any components with intended functions described in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Table 2.4-18 identifies the component types subject to an AMR and structure intended function. Some component types include structural bolting, concrete elements, equipment supports and foundations, hatches and plugs, and manholes and duct banks. Intended functions include structural support, shelter, protection and missile barrier. The AMR results for these components are provided in Table 3.5.2-18 of the LRA.

2.4.18.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the yard structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the yard structures SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical

This section documents the staff's review of the applicant's scoping and screening results for electrical and 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 meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

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

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SSCs with intended functions, the staff sought to determine whether (1) the intended 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 SSCs meeting neither of these criteria, the staff confirmed that these SSCs were subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1 Electrical Systems

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and I&C systems. The bounding approach for the scoping of electrical systems includes, in the scope of license renewal, all electrical and I&C systems as well as electrical components needed for offsite power recovery following an SBO.

The IPA approach for the review of the electrical and I&C components that are within the scope of license renewal eliminates the need to uniquely identify each individual component and its specific location and precludes improper exclusion of components from an AMR.

The IPA screening process groups all electrical and I&C components in commodity groups and identifies those electrical commodity groups that are subject to an AMR by applying 10 CFR 54.21 (a)(1)(i) and (ii). Electrical components in the SBO offsite power recovery path are identified based on their intended functions. Components interfacing with the electrical and I&C components are assessed in the appropriate mechanical or structural sections. LRA Table 2.5.2-1 identifies the following components/commodities subject to an AMR per the IPA screening process along with and their license renewal intended functions:

- cable connections (metallic parts) – electrical continuity
- connector contacts for electrical connectors exposed to borated water leakage – electrical continuity
- fuse holders (not part of active equipment): metallic clamps – electrical continuity
- high-voltage insulators – insulate (electrical)
- insulation material for electrical cables and connections – insulate (electrical)
- metal-enclosed bus (MEB) – electrical continuity, shelter, protection, insulate (electrical)
- switchyard bus and connections, transmission conductors, and transmission connectors – electrical continuity

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5, LRA Section 2.1.3.4 (SBO), and UFSAR Chapters 7 and 8 using the evaluation methodology described 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 electrical and I&C components with intended functions delineated under 10 CFR 54.4(a).

10 CFR 54.4(a)(3) requires that all SSCs relied on in safety analyses or plant evaluation to perform a function that demonstrates compliance with NRC regulations for SBO (10 CFR 50.63) be included within the scope of license renewal. SRP-LR section 2.5.2.1.1 provides the guidance to identify electrical and I&C systems components that are relied upon to meet the requirements of the SBO Rule for license renewal. This includes equipment that is required to cope with an SBO (e.g., alternate AC (AAC) power sources) meeting the requirements in 10 CFR 54.4(a)(3) and the plant system portion of the offsite power system, including the electrical distribution equipment out to the first circuit breaker with the offsite distribution system

(i.e., equipment in the switchyard), that is used to connect the plant to the offsite power source meeting the requirements under 10 CFR 54.4(a)(3).

In addition, 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 is supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. SSCs that are relied upon to meet the requirements of the SBO Rule in both circuits are to be included within the scope of license renewal.

In LRA Section 2.1.3.4, "Scoping for Regulated Events," the applicant provided the Byron SBO recovery boundary and the Braidwood SBO recovery boundary in Figures 2.1-2 and 2.1-3, respectively, and also identified components that are within the scope of license renewal on the plant side of the SBO boundaries. However, during its review, the staff noticed that both Figures 2.1-2 and 2.1-3 did not show circuit breakers 1412, 1422, 2412, and 2422 between the 345-kV circuit breakers and the 4160-V ESF buses. By letter dated November 25, 2013, the staff issued RAIs 2.1.3.4-1 and 2.1.3.4-3, requesting that the applicant clarify the SBO recovery path components identified in Figures 2.1-2 and 2.1-3 as being within the scope of license renewal.

In its response letters dated December 17, 2013, and March 21, 2014, the applicant provided revised LRA Figures 2.1-2 and 2.1-3 and updated descriptions of SBO power paths to the 4.160-kV buses. The 4.160 kV buses receive recovery power from the offsite sources or the onsite AAC sources. The applicant included, within the scope of license renewal, the circuits between the 4.160 kV ESF buses up to and including the 345 kV circuit breakers supplying the SATs and between the 4.160 kV ESF buses up to and including the AAC DGs.

For Byron Unit 1, as shown on Figure 2.1-2, the circuits supplying power to the ESF buses (141, 142) consist of the normal circuit from the 345 kV switchyard circuit breakers (5-6, 3-7, 6-7) through the SATs (142-1, 142-2) and circuit breakers (1412, 1422); the reserve circuit from the 345 kV switchyard circuit breakers (12-13, 7-10, 7-13) through the SATs (242-1, 242-2) and circuit breakers (2412, 2422), (2414, 2424), and (1414, 1424); and the AAC circuit from the DGs (DG2A, DG2B) through breakers (2413, 2423), (2414, 2424), and (1414, 1424).

For Byron Unit 2, as shown on Figure 2.1-2, the circuits supplying power to the ESF buses (241, 242) consist of the normal circuit from the 345 kV switchyard circuit breakers (12-13, 7-10, 7-13) through the SATs (242-1, 242-2) and circuit breakers (2412, 2422); the reserve circuit from the 345-kV switchyard circuit breakers (5-6, 3-7, 6-7) through the SATs (142-1, 142-2) and circuit breakers (1412, 1422), (1414, 1424), and (2414, 2424); and the AAC circuit from the DGs (DG1A, DG1B) through breakers (1413, 1423), (1414, 1424), and (2414, 2424).

For Braidwood Unit 1, as shown on Figure 2.1-3, the circuits supplying power to the ESF buses (141, 142) consist of the normal circuit from the 345 kV switchyard circuit breakers (3-4, 4-7) through the SATs (142-1, 142-2) and circuit breakers (1412, 1422); the reserve circuit from the 345-kV switchyard circuit breakers (11-14, 14-15) through the SATs (242-1, 242-2) and circuit breakers (2412, 2422), (2414, 2424), and (1414, 1424); and the AAC circuit from the DGs (DG2A, DG2B) through breakers (2413, 2423), (2414, 2424), and (1414, 1424).

For Braidwood Unit 2, as shown on Figure 2.1-3, the circuits supplying power to the ESF buses (241, 242) consist of the normal circuit from the 345-kV switchyard circuit breakers (11-14, 14-15) through the SATs (242-1, 242-2) and circuit breakers (2412, 2422); the reserve circuit from the 345-kV switchyard circuit breakers (3-4, 4-7) through the SATs (142-1, 142-2) and circuit breakers (1412, 1422), (1414, 1424), and (2414, 2424); and the AAC circuit from the DGs (DG1A, DG1B) through breakers (1413, 1423), (1414, 1424), and (2414, 2424).

The switchyard bus and connections, control circuits associated with the circuit breakers, disconnect switches, transmission conductors and connections, high-voltage insulators, switchyard structures and supports, MEB, insulated cables and connections, and cables connections (metallic parts) within the SBO recovery boundaries are also included within the scope of license renewal. The switchyard structures and supports are evaluated in Section 2.4, "Scoping and Screening Results: Structures." Based on the review of this information, the staff concludes that the scoping is consistent with the guidance in SRP-LR Section 2.5.2.1.1. The staff concerns described in RAI 2.1.3.4-1 and RAI 2.1.3.4-3 are resolved.

The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The applicant did not include cable tie-wraps in the electrical commodity groups subject to an AMR because cable tie-wraps do not have a license renewal intended function at BBS. The applicant stated that BBS have no current license basis requirements that cable tie-wraps remain functional during and following DBEs, and that cable tie-wraps are not credited in the BBS design basis in terms of any 10 CFR 54.4 intended function. The applicant clarified that cables tie-wraps are used to bundle wires and cables together to keep the wire and cable runs neat and to restrain cables and wires to facilitate cable installation and maintenance at BBS. In addition, the applicant stated that cable tie-wraps are not credited for maintaining cable ampacity, cable minimum bending radius, or cables within vertical raceways, and are not credited in the seismic qualification of cable trays. Based on the review of this information and the UFSAR, the staff finds that the exclusion of cable-tie wraps from the electrical commodity groups subject to an AMR is acceptable.

The applicant did not include uninsulated ground conductors in the electrical commodity groups subject to an AMR because uninsulated ground conductors do not perform a license renewal intended function at BBS. The applicant clarified that uninsulated ground conductors are provided for equipment and personnel protection at BBS. The staff reviewed the UFSAR and found that uninsulated ground conductors are not credited in the BBS design basis. Therefore, the staff concludes that the exclusion of uninsulated ground conductors from the electrical commodity groups subject to an AMR is acceptable.

The applicant did not include elements, resistance temperature detectors, sensors, thermocouples, and transducers in the electrical commodities subject to an AMR. By letter dated November 25, 2013, the staff issued RAI 2.5.2.1-1, requesting that the applicant clarify whether a pressure boundary is applicable to each of these components. In its response letter dated December 17, 2013, the applicant stated that the above components as well as electric heaters also serve a mechanical pressure boundary function, and the pressure boundary function for these components is addressed in the mechanical review in Section 2.3, "Scoping and Screening Results: Mechanical." The staff finds the applicant's response acceptable. The staff concern described in RAI 2.5.2.1-1 is resolved.

2.5.1.3 Conclusion

Based on its review of the LRA, the UFSAR, RAI responses, and license renewal SBO recovery boundary figures, the staff concludes that the applicant appropriately identified the electrical and

I&C systems components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the electrical and I&C systems components 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). The staff also finds that the applicant's scoping and screening methodology is consistent with the staff's position on the treatment of safety-related and nonsafety-related SSCs within the scope of license renewal and on SCs subject to an AMR as required by 10 CFR 54.4 and 10 CFR 54.21(a)(1).

On the basis of its review, the staff concludes that the applicant 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).

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This safety evaluation report (SER) section evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, (BBS) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

In Appendix B of its license renewal application (LRA), Exelon Generation Company, LLC (Exelon or the applicant), described the 45 AMPs that it relies on to manage or monitor the aging of passive, long-lived structures and components (SCs).

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

3.0 Applicant's Use of the Generic Aging Lessons Learned Report

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

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

The GALL Report identifies the following:

- systems, structures, and components (SSCs)
- SCs materials
- environments to which the SCs are exposed
- aging effects of the materials and environments
- AMPs credited with managing or monitoring the aging effects
- 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* (CFR), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”; the guidance provided in NUREG-1800, Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), dated December 2010; and the guidance provided in the GALL Report.

In addition to its LRA review, the staff conducted an onsite audit of selected AMPs at Byron during the weeks of August 19-30, 2013, and at Braidwood during the weeks of October 30-31, 2013, and December 2-6, 2013, as described in the “Aging Management Programs Audit Report regarding the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2,” dated March 13, 2014. The onsite audits and reviews are designed for maximum efficiency of the staff’s LRA review. The applicant can respond to questions, the staff can readily evaluate the applicant’s responses, and the need for formal correspondence between the staff and the applicant is reduced, resulting in improved review efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format agreed to by the staff and the Nuclear Energy Institute (NEI) by letter dated December 15, 2011. The organization of LRA Section 3 parallels that of SRP-LR, Chapter 3. LRA Section 3 presents the results of AMR information in the following two table types:

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

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

In Table 1s, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In Table 2s, the applicant identified the linkage between the scoping and screening results in LRA Section 2 and the AMRs in LRA Section 3.

3.0.1.1 Overview of Table 1s

Each Table 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 applicant used the “Discussion” column to provide clarifying and amplifying information. The following are examples of information that might be contained within this column:

- further evaluation recommended—information or reference to where that information is located name of a plant-specific program
- exceptions to the GALL Report assumptions

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

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

3.0.1.2 Overview of Table 2s

Each Table 3.x.2-y (Table 2) provides the detailed AMR results 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 (RCSs), engineered safety features (ESFs), auxiliary systems). For example, the ESF group contains tables specific to the containment spray system (CSS), residual heat removal (RHR) system, and safety injection system (SIS). Each Table 2 consists of the following nine columns:

(1) Component Type: The first column lists LRA Section 2 component types subject to an AMR in alphabetical order.

(2) Intended Function: The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.1-1.

(3) Material: The third column lists the particular construction material(s) for the component type.

(4) Environment: The fourth column lists the environments to which the component types are exposed. A list of these environments in LRA Tables 3.0-1, 3.0-2, and 3.0-3 indicates internal and external service environments.

(5) Aging Effect Requiring Management (AERM): The fifth column lists AERM. As part of the AMR process, the applicant determined any AERM for each combination of material and environment.

(6) AMPs: The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.

(7) The GALL Report Item: The seventh column lists the GALL Report item(s) identified in the LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there were no corresponding items in the GALL Report, the applicant left the column blank to identify the AMR results in the LRA tables corresponding to the items in the GALL Report tables.

(8) Table 1 Item: The eighth column lists the corresponding summary item number from LRA Table 1. If the applicant identifies in each LRA Table 2 AMR results consistent with the GALL Report, the Table 1 AMR item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, column 8 is left blank. In this manner, the information from the two tables can be correlated.

(9) Notes: The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI working group and will be used in future

LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the AMR 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 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, enhancements, or both, the staff conducted either an audit or a technical review of the item to determine consistency. In addition, the staff conducted either an audit or a technical review of the applicant's technical justifications for the exceptions or the adequacy of the enhancements.

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

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

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

These audits and technical reviews of the applicant's AMPs and AMRs determine if 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:

(1) "scope of program"—should include the specific SCs subject to a license renewal AMR.

(2) "preventive actions"—should prevent or mitigate aging degradation.

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

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

(5) “monitoring and trending”—should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.

(6) “acceptance criteria”—these 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”—these actions, including root cause determination and prevention of recurrence, should be timely.

(8) “confirmation process”—should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) “administrative controls”—should provide for a formal review and approval process.

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

Details of the staff’s audit evaluation of program elements 1 through 6 and 10 are documented in the AMP audit report and summarized in SER Section 3.0.3. The staff reviewed the applicant’s Quality Assurance (QA) Program and documented its evaluations in SER Section 3.0.4. The staff’s evaluation of the QA Program included an assessment of the “corrective actions,” “confirmation process,” and “administrative controls” program elements.

The staff reviewed the information on the “operating experience” program element and documented its evaluation in SER Sections 3.0.3 and 3.0.5.

3.0.2.2 Review of AMR Results

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

For component groups evaluated in the GALL Report for which the applicant claimed consistency and for which it does not recommend further evaluation, the staff determined, on the basis of its review, whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A through E, indicating how the AMR is consistent with the GALL Report.

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

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

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

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

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

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, the SRP-LR, the 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 3.0-1 below presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates whether the AMP is an existing or new program, the GALL Report AMP with which the applicant claimed consistency, the section of this SER in which the staff's evaluation of the program is documented, and the staff's final disposition of the AMP.

Table 3.0-1 Byron and Braidwood Aging Management Programs

Applicant AMP	LRA Sections	New or Existing Program	LRA initial Comparison to the GALL Report	GALL Report AMP(s)	SER Section *(Disposition)*
American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	A.2.1.1 B.2.1.1	Existing	Consistent with enhancement	XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	3.0.3.2.1 *(Consistent with enhancement)*
Water Chemistry	A.2.1.2 B.2.1.2	Existing	Consistent	XI.M2, Water Chemistry	3.0.3.1.1 *(Consistent)*
Reactor Head Closure Stud Bolting	A.2.1.3 B.2.1.3	Existing	Consistent with exception and enhancement	XI.M3, Reactor Head Closure Stud Bolting	3.0.3.2.2 *(Consistent with exception and enhancement)*
Boric Acid Corrosion	A.2.1.4 B.2.1.4	Existing	Consistent	XI.M10, Boric Acid Corrosion	3.0.3.1.2 *(Consistent)*
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	A.2.1.5 B.2.1.5	Existing	Consistent	XI.M11B, Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (Pressurized Water Reactors (PWRs) only)	3.0.3.1.3 *(Consistent)*
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 CASS	3.0.3.1.4 *(Consistent)*
PWR Vessel Internals	A.2.1.7 B.2.1.7	New	Consistent with exception	XI.M16A, PWR Vessel Internals	3.0.3.2.3 *(Consistent with exception)*
Flow-Accelerated Corrosion	A.2.1.8 B.2.1.8	Existing	Consistent	XI.M17, Flow-Accelerated Corrosion	3.0.3.1.5 *(Consistent with enhancement)*
Bolting Integrity	A.2.1.9 B.2.1.9	Existing	Consistent with enhancements	XI.M18, Bolting Integrity	3.0.3.2.4 *(Consistent with enhancements)*
Steam Generators	A.2.1.10 B.2.1.10	Existing	Consistent with exception and enhancements	XI.M19, Steam Generators	3.0.3.2.5 *(Consistent with exception and enhancements)*

Applicant AMP	LRA Sections	New or Existing Program	LRA initial Comparison to the GALL Report	GALL Report AMP(s)	SER Section *(Disposition)*
Open-Cycle Cooling Water System	A.2.1.11 B.2.1.11	Existing	Consistent with enhancement	XI.M20, Open-Cycle Cooling Water System	3.0.3.2.6 *(Consistent with enhancements)*
Closed Treated Water Systems	A.2.1.12 B.2.1.12	Existing	Consistent with enhancements	XI.M21A, Closed Treated Water Systems	3.0.3.2.7 *(Consistent with enhancements)*
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	3.0.3.2.8 *(Consistent with enhancements)*
Compressed Air Monitoring	A.2.1.14 B.2.1.14	Existing	Consistent with exception and enhancement	XI.M24, Compressed Air Monitoring	3.0.3.2.9 *(Consistent with exception and enhancement)*
Fire Protection	A.2.1.15 B.2.1.15	Existing	Consistent with enhancements	XI.M26, Fire Protection	3.0.3.2.10 *(Consistent with enhancements)*
Fire Water System	A.2.1.16 B.2.1.16	Existing	Consistent with enhancements	XI.M27, Fire Water System	3.0.3.2.11 *(Consistent with exceptions and enhancements)*
Aboveground Metallic Tanks	A.2.1.17 B.2.1.17	New	Consistent with exception	XI.M29, Aboveground Metallic Tanks	3.0.3.2.12 *(Consistent with exception)*
Fuel Oil Chemistry	A.2.1.18 B.2.1.18	Existing	Consistent with enhancements	XI.M30, Fuel Oil Chemistry	3.0.3.2.13 *(Consistent with enhancements)*
Reactor Vessel Surveillance	A.2.1.19 B.2.1.19	Existing	Consistent with enhancement	XI.M31, Reactor Vessel Surveillance	3.0.3.2.14 *(Consistent with enhancements)*
One-Time Inspection	A.2.1.20 B.2.1.20	New	Consistent	XI.M32, One-Time Inspection	3.0.3.1.6 *(Consistent)*
Selective Leaching	A.2.1.21 B.2.1.21	New	Consistent	XI.M33, Selective Leaching	3.0.3.1.7 *(Consistent)*
One-Time Inspection of ASME Code Class 1 Small Bore Piping	A.2.1.22 B.2.1.22	New	Consistent	XI.M35, One-Time Inspection of ASME Code Class 1 Small Bore-Piping	3.0.3.1.8 *(Consistent)*

Applicant AMP	LRA Sections	New or Existing Program	LRA initial Comparison to the GALL Report	GALL Report AMP(s)	SER Section *(Disposition)*
External Surfaces Monitoring of Mechanical Components	A.2.1.23 B.2.1.23	New	Consistent	XI.M36, External Surfaces Monitoring of Mechanical Components	3.0.3.1.9 *(Consistent)*
Flux Thimble Tube Inspection	A.2.1.24 B.2.1.24	Existing	Consistent with exception and enhancements	XI.M37, Flux Thimble Tube Inspection	3.0.3.1.10 *(Consistent with exception and enhancements)*
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	A.2.1.25 B.2.1.25	New	Consistent	XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.0.3.1.11 *(Consistent)*
Lubricating Oil Analysis	A.2.1.26 B.2.1.26	Existing	Consistent	XI.M39, Lubricating Oil Analysis	3.0.3.1.12 *(Consistent)*
Monitoring of Neutron-Absorbing Materials Other than Boraflex	A.2.1.27 B.2.1.27	Existing	Consistent	XI.M40, Monitoring of Neutron-Absorbing Materials Other than Boraflex	3.0.3.1.13 *(Consistent with enhancement)*
Buried and Underground Piping	A.2.1.28 B.2.1.28	Existing	Consistent with exceptions and enhancements	XI.M41, Buried and Underground Piping and Tanks	3.0.3.2.15 *(Consistent with exceptions and enhancements)*
ASME Section XI, Subsection IWE	A.2.1.29 B.2.1.29	Existing	Consistent with enhancement	XI.S1, ASME Section XI, Subsection IWE	3.0.3.2.16 *(Consistent with enhancements)*
ASME Section XI, Subsection IWL	A.2.1.30 B.2.1.30	Existing	Consistent with enhancements	XI.S2, ASME Section XI, Subsection IWL	3.0.3.2.17 *(Consistent with enhancements)*
ASME Section XI, Subsection IWF	A.2.1.31 B.2.1.31	Existing	Consistent with exceptions and enhancements	XI.S3, ASME Section XI, Subsection IWF	3.0.3.2.18 *(Consistent with exceptions and enhancements)*
10 CFR Part 50, Appendix J	A.2.1.32 B.2.1.32	Existing	Consistent	XI.S4, 10 CFR Part 50, Appendix J	3.0.3.1.14 *(Consistent)*
Masonry Walls	A.2.1.33 B.2.1.33	Existing	Consistent with enhancements	XI.S5, Masonry Walls	3.0.3.2.19 *(Consistent with enhancements)*

Applicant AMP	LRA Sections	New or Existing Program	LRA initial Comparison to the GALL Report	GALL Report AMP(s)	SER Section *(Disposition)*
Structures Monitoring	A.2.1.34 B.2.1.34	Existing	Consistent with enhancements	XI.S6, Structures Monitoring	3.0.3.2.20 *(Consistent with enhancements)*
RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	A.2.1.35 B.2.1.35	Existing	Consistent with enhancements	XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	3.0.3.2.21 *(Consistent with enhancements)*
Protective Coating Monitoring and Maintenance Program	A.2.1.36 B.2.1.36	Existing	Consistent with enhancements	XI.S8, Protective Coating Monitoring and Maintenance Program	3.0.3.2.22 *(Consistent with enhancements)*
Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.37 B.2.1.37	New	Consistent	XI.E1, Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	3.0.3.1.15 *(Consistent)*
Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	A.2.1.38 B.2.1.38	New	Consistent	XI.E2, Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	3.0.3.1.16 *(Consistent)*
Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.39 B.2.1.39	New	Consistent	XI.E3, Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	3.0.3.1.17 *(Consistent)*
Metal Enclosed Bus	A.2.1.40 B.2.1.40	Existing	Consistent with enhancements	XI.E4, Metal Enclosed Bus	3.0.3.2.23 *(Consistent with enhancements)*
Fuse Holders (Byron Only)	A.2.1.41 B.2.1.41	New	Consistent	XI.E5, Fuse Holders	3.0.3.1.18 *(Consistent)*

Applicant AMP	LRA Sections	New or Existing Program	LRA initial Comparison to the GALL Report	GALL Report AMP(s)	SER Section *(Disposition)*
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.42 B.2.1.42	New	Consistent	XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	3.0.3.1.19 *(Consistent)*
Fatigue Monitoring	A.3.1.1 B.3.1.1	Existing	Consistent with enhancements	X.M1, Fatigue Monitoring	3.0.3.2.24 *(Consistent with enhancements)*
Concrete Containment Tendon Prestress	A.3.1.2 B.3.1.2	Existing	Consistent with enhancement	X.S1, Concrete Containment Tendon Prestress	3.0.3.2.25 *(Consistent with enhancement)*
Environmental Qualification (EQ) of Electric Components	A.3.1.3 B.3.1.3	Existing	Consistent	X.E1, Environmental Qualification (EQ) of Electrical Components	3.0.3.1.20 *(Consistent)*

3.0.3.1 AMPs Consistent with the GALL Report

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

- Water Chemistry
- Boric Acid Corrosion
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components
- Thermal Aging Embrittlement of CASS
- Flow-Accelerated Corrosion
- One-Time Inspection
- Selective Leaching
- One-Time Inspection of ASME Code Class 1 Small Bore-Piping
- External Surfaces Monitoring of Mechanical Components
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- Monitoring of Neutron-Absorbing Materials Other than Boraflex
- 10 CFR Part 50, Appendix J

- Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits
- Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Fuse Holders (Byron Only)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Environmental Qualification (EQ) of Electric Components

3.0.3.1.1 Water Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.2, as revised by the applicant's letter dated April 6, 2015, describes the existing Water Chemistry Program as consistent, with an exception, with GALL Report AMP XI.M2, "Water Chemistry." The BBS Water Chemistry Program manages the loss of material due to corrosion, cracking due to stress-corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to reactor coolant, steam, treated borated water, and treated water in primary and certain secondary systems. The program monitors and controls water chemistry parameters such as pH, chloride, fluorides, dissolved oxygen (DO), and sulfate in accordance with Electric Power Research Institute (EPRI) 3002000505, "PWR Primary Water Chemistry Guidelines," Revision 7, and EPRI 1016555, "PWR Secondary Water Chemistry Guidelines," Revision 7. The LRA also states that one-time inspections will be performed on components in low and stagnant flow areas.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M2.

Exception. LRA Section B.2.1.2, as revised by the applicant's letter dated April 6, 2015, includes an exception to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this exception, the applicant stated the EPRI reports such as "PWR Primary Water Chemistry Guidelines" are industry reports, which are periodically reviewed and revised by industry experts to incorporate recent industry operating experience (OE) and best practices. Additionally, the applicant stated that BBS will use EPRI "PWR Primary Water Chemistry Guidelines" Revision 7 rather than Revision 6, which is the GALL Report recommendation. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M2 and finds it acceptable because Revision 7 of the "PWR Primary Water Chemistry Guidelines" incorporates the latest industry OE and best practices. Additionally, the "PWR Primary Water Chemistry Guidelines" Revision 7 does not take away or relax any of the relevant guidelines from the Revision 6 document.

Based on its audit of the applicant's Water Chemistry Program, the staff finds that program elements 1 through 6, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M2. The staff also reviewed the exception associated with the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria" program elements, and the justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.2 summarizes OE related to the Water Chemistry Program.

Byron and Braidwood Stations.

- International operating experience showed that elevated reactor coolant pH values greater than 7.2 resulted in improved dose rates. Exelon chemistry personnel recognized that elevated pH values would also improve primary water stress corrosion cracking (PWSCC) mitigation. Westinghouse Electric Corporation (Westinghouse) performed detailed evaluations for operation at Byron and Braidwood with elevated pH values greater than 7.2. Westinghouse concluded that a variable pH program, which maintains primary system water in a pH range up to 7.4, was feasible and beneficial for dose reduction and aging management. The new variable pH program was implemented at Byron Unit 1 and Braidwood Unit 1 in 2008, at Byron Unit 2 in 2009, and at Braidwood Unit 2 in 2010.
- Zinc injection into the RCS of PWRs has demonstrated benefits for mitigating SCC. Exelon and Westinghouse performed evaluations and verified that zinc injection programs will not adversely affect primary system performance while mitigating SCC. The zinc injection was implemented at Byron Unit 2 in 2005, Braidwood Unit 2 in 2006, and Byron Unit 1 and Braidwood Unit 1 in 2010. Actual dose rates have been reduced by approximately 50 percent after target zinc concentrations were established at each Unit. Exelon is currently investigating increasing the average zinc concentration target from 5 ppb to 10 ppb.
- In 2010, Byron and Braidwood implemented the use of chemical dispersants to increase secondary system side corrosion product removal from the steam generators. Dispersants are injected into the feedwater system to minimize the propensity for corrosion products to deposit in the steam generators during power operation. The dispersants tend to keep the corrosion products in liquid solution, which makes it easier for the steam generator blowdown system to remove the corrosion products from the steam generators.

Byron Station.

- In 2010, Byron implemented a mixed amine program, which simultaneously uses ethanolamine (ETA) and methoxypropylamine (MPA) for secondary systems pH control to improve mitigation of flow-accelerated corrosion. The implementation of this program was prompted by inspections of Unit 2 steam generator internal moisture separators, which indicated accelerated wear rates since a recent power uprate. The mixed amine program consists of optimizing feedwater MPA and ETA target concentrations to ensure pH protection throughout the steam cycle.

Braidwood Station.

- In 2006, Braidwood placed into service an ultraviolet (UV)-peroxide system to reduce the total organic carbon (TOC) concentrations for water recycled to the primary water storage tanks (PWSTs). This action was prompted by a corrective action, which documented that TOC concentrations in the PWST were greater than the Exelon goal of 100 ppb TOC. As a result of this modification, primary system makeup TOC concentrations were significantly reduced from approximately 500 ppb in December 2006 to less than 100 ppb in December 2007.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. During its review, the staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M2 was evaluated.

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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to ongoing implementation of the existing Water Chemistry Program for managing the effects of aging for applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Water Chemistry Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 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 GALL Report AMP XI.M10, "Boric Acid Corrosion." The LRA states that the AMP addresses mechanical, electrical, and structural components that are susceptible to boric acid corrosion due to leakage from systems that contain borated water. The LRA also states that the program manages loss of material for all susceptible components and increased resistance of connection/corrosion for electrical contacts. The LRA further states that the AMP proposes to manage these aging effects through visual examinations of surfaces that are potentially exposed to borated water leakage, and following the discovery of a leak, the leak source is identified, the boric acid residue is cleaned, any damage is assessed, and followup inspections are performed.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M10. Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M10.

Operating Experience. LRA Section B.2.1.4 summarizes OE related to the Boric Acid Corrosion Program. In January 2009, Byron used a robotic crawler in the Unit 1 containment to verify the presence of a borated water leak, which had been initially discovered by radiation monitors. After removal of insulation, the leak source was identified as the body-to-bonnet bolted connection in a reactor coolant loop drain valve. The bolts were retorqued to stop the leakage; and, during the next refueling outage, the body-to-bonnet gasket was replaced. In June 2011, the Braidwood Unit 1 RCS Water Inventory Balance Surveillance exceeded the action level for unidentified RCS leak rate, which was followed up with an inspection that located the leakage source as a pressurizer spray bypass valve. The valve was isolated and later replaced with a valve of more reliable design. The leakage targets were identified, and no degradation was found. The applicant performed Focused Area Self-Assessments (FASAs) for the BBS Boric Acid Corrosion Control programs in 2010 and found both programs to be in compliance with regulations and aligned with industry standards. Although the self-assessments did identify program deficiencies associated with procedural adherence and human performance, these deficiencies were entered into the corrective action program (CAP) to track their resolution, and all assignments associated with these deficiencies have been completed.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. During its review, the staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M10 was evaluated.

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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to ongoing implementation of the existing Boric Acid Corrosion Program for managing the effects of aging for applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Boric Acid Corrosion Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Summary of Technical Information in the Application. LRA Section B.2.1.5 describes the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program as an existing program, consistent with GALL Report AMP XI.M11B. LRA Section B.2.1.5 states that the applicant's program is a condition monitoring program that manages the aging effects of PWSCC of nickel-alloy components and associated welds. This program also manages loss of material due to boric-acid-induced corrosion in susceptible components in the vicinity of nickel alloy RCPB components. The program includes periodic bare-metal visual, surface, and/or volumetric examinations of nickel alloy RCPB components that are susceptible to PWSCC and loss of material due to boric acid-induced corrosion of related alloy steel components as a result of nickel-alloy leakage. In addition, the program includes inspection requirements for reactor pressure vessel (RPV) upper heads. The inspection requirements are consistent with ASME Section XI Code Case N-722-1, "Additional Examinations for PWR Pressure Retaining Welds in Class 1 Components Fabricated with Alloy 600/82/182 Materials," subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E); Code Case N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds," subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D); and Code Case N-770-1, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities," subject to conditions specified in 10 CFR 50.55a(g)(6)(ii)(F). The program provides examination methods to detect PWSCC and significant age-related degradation on susceptible components.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M11B. Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M11B.

Operating Experience. LRA Section B.2.1.5 summarizes OE related to the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program. The LRA states that during Byron Unit 1 Refueling Outage (spring 2011), the RPV head penetrations were examined per the requirements of 10 CFR 50.55a and ASME Section XI Code Case N-729-1 as amended by 10 CFR 50.55a(g)(6)(ii)(D). The LRA also states that even though there was no evidence of leakage, the volumetric examinations revealed indication of cracking on four penetrations (Nos. 31, 34, 64, and 76). In addition, the LRA states that these four penetrations were repaired, and that volumetric examinations during the subsequent outage in Fall of 2012 did not reveal any evidence of cracking or leakage of these reactor vessel head penetrations.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

During the audit and staff's review of the OE database provided by the applicant, the staff noticed that the applicant performed ultrasonic testing (UT) examination of the control rod drive mechanism (CRDM) penetration nozzles at Byron Station, Unit 1, in 2011, in accordance with ASME Code Case N-729-1. During the UT examination, the applicant found that CRDM nozzles Nos. 4 and 8 experienced wear as a result of interactions with the centering pads of CRDM nozzle thermal sleeves. In addition, the staff noticed that the applicant's OE indicates that loss of UT data occurred above the J-groove welds on these penetration nozzles because water couplant could not make up the gap between the UT probe and the CRDM nozzle in the wear areas. The applicant's OE further indicates that it was not possible to determine the exact thickness values of the CRDM nozzles in the wear area because the zero-degree UT probe, which could measure the nozzle thickness, could not receive a UT signal due to the noted couplant issues.

As discussed above, the staff noticed that the applicant's UT examination of the CRDM nozzles at Byron Station, Unit 1, identified that the CRDM nozzles experienced wear due to the interactions between CRDM nozzles and CRDM nozzle thermal sleeves. In addition, the staff noticed that LRA Table 3.1.2-2 indicates that the thermal sleeves of reactor vessel head nozzles are subject to loss of material due to wear. However, the staff noticed that neither the LRA or applicant's program basis documents clearly describe how these wear indications will be monitored and managed to maintain the intended functions of the reactor vessel head CRDM nozzles.

By letter dated December 12, 2013, the staff issued RAI B.2.1.5-1 requesting that the applicant provide the following:

- Part 1 of RAI B.2.1.5-1, the staff requested that the applicant provide the following baseline information related to the observed wear indications of the CRDM penetration nozzles: (a) the total number of CRDM penetration nozzles, and the number of penetration nozzles with wear indications for each of the Byron and Braidwood; (b) the maximum depth of wear indications (if measured) and CRDM nozzle wall thickness for each unit; (c) clarification on whether the wear from the centering pads was at pressure boundary locations; (d) the applicant's acceptance basis for continued operation with the wear indications, including the maximum acceptable wear depth that was determined in the applicant's analysis; and (e) clarification on whether all wear indications are located in the examination volume specified in the program (e.g., the volumetric examination of ASME Code Case N-729-1).
- In Part 2 of the RAI, the staff requested that the applicant clarify whether this wear may occur for other types of reactor vessel head nozzles (e.g., reactor vessel level indication system penetration nozzles). The staff also requested that, if so, the applicant provide information requested in Part 1, as applied to other types of reactor vessel head nozzles.
- In Part 3 of the RAI, the staff requested that the applicant describe how loss of material due to wear of reactor vessel head penetration nozzles will be monitored and managed. The staff also requested that, as part of the response, the applicant describe the inspection method, scope, and frequency of the examination for managing loss of material due to wear of the CRDM nozzles.

- In Part 4 of the RAI, the staff requested that the applicant clarify whether and how the water couplant issue was resolved (i.e., loss of UT data due to the absence of couplant between the UT probe and nozzle near the wear indications). The staff also requested that, as part of the response, the applicant describe the extent of loss of UT data (e.g., the percentage of examination volume, which was not examined for cracking or loss of material). The staff further requested that, if the issue has not been resolved, the applicant justify why loss of UT data near the wear locations is acceptable in managing cracking and wear of the reactor vessel head nozzles during the period of extended operation.
- In Part 5 of RAI B.2.1.5-1, the staff requested that the applicant identify all program enhancements and additional AMR results as necessary. The staff also requested that the applicant ensure that the LRA is consistent with the applicant's response.

By letter dated January 13, 2014, the applicant provided its response to RAI B.2.1.5-1. In its response to Request Part 1a of the RAI, the applicant stated that there are a total of 78 CRDM penetration nozzles on the reactor vessel head on each unit. The applicant also indicated that each unit has 55 CRDM nozzle locations having thermal sleeves and the remaining 23 penetrations do not have thermal sleeves. The applicant further stated that these 55 locations include 53 penetrations with control rod drive assemblies and two penetrations with reactor vessel level instrumentation for each unit of Byron and Braidwood. In addition, the applicant stated that during the UT examinations of the CRDM nozzles, wear indications have been observed on nine CRDM penetration nozzles (P1 through P9) near the center of the reactor vessel head on all four units at BBS.

In the response, the applicant stated that the depth of these wear indications could not be measured. The applicant also stated that the wear on the other CRDM nozzles that contain thermal sleeves, outside of the reactor vessel head central region, is outside of the volume examined during the J-groove weld examinations and cannot be measured directly with the existing nondestructive examination (NDE) techniques but can be inferred from the wear observed on the thermal sleeves. The applicant further indicated that the wear of the CRDM nozzle results from the interactions with the centering pads of the nozzle thermal sleeves.

In its response to Request Part 1b, the applicant stated that the wear indications of the CRDM nozzles were initially noted during the J-groove weld examinations on the CRDM nozzles with CRDM thermal sleeves near the central region of the reactor vessel head. The applicant also stated that the actual depth of these indications could not be measured with the existing techniques. The applicant further stated that the centering pads extend 0.1075 in., which is the pad thickness beyond the outside diameter of the thermal sleeve. The applicant further stated that the wall thickness of the CRDM penetration nozzles is 0.625 in. at the thinnest location.

In its response to Request Part 1c, the applicant stated that the wear indications from the centering pads are located inside the nickel alloy CRDM penetration nozzles, which are part of the RCPB.

In its response to Request Part 1d, the applicant stated that evaluations have been performed for three of the four units (i.e., Braidwood Units 1 and 2 and Byron Unit 1) for the CRDM nozzle wear, which allow 2 cycles of operation without additional inspections. The applicant also stated that the evaluation for the fourth unit, Byron Unit 2, is presently in progress and is expected to be completed by the first quarter of 2014 with similar results. The applicant further stated that evaluations for continued operations conservatively considered the maximum possible reduced

CRDM nozzle wall thickness due to wear (i.e., the maximum wear depth) and determined that reasonable margin existed to allow two cycles of operation and allow time for more detailed evaluations to be completed. The applicant further stated that the assumed maximum wear depth is the maximum possible penetration nozzle wear of 0.1075 in., which is the distance the centering pad extends from the outside diameter of the thermal sleeve.

In addition, the applicant indicated that the evaluations, which were performed by Westinghouse for the current condition of the Byron and Braidwood units, provided the technical basis for the acceptability of the wear including the primary stresses, primary plus secondary (P+Q) stress intensity ranges, and fatigue usage assessments. The applicant stated that these evaluations were based on the conservative load combinations, reduction in wall thickness assumed in the evaluation, and low cumulative fatigue usage factors of CRDM nozzles at Byron and Braidwood (i.e., 0.021 compared to a limit of 1.0). The applicant also stated that because the limiting stress location in the CRDM nozzle is at the top of the J-groove weld, the CRDM nozzles located in the center of the reactor vessel head with reduced wall thickness become the limiting locations, since the wear in these nozzles is adjacent to the J-groove weld. The applicant further stated that the presence of wear in the center region nozzles can be observed (not measured) during the J-groove weld examinations, and therefore the maximum possible wear depth of 0.1075 in. was assumed in the evaluations.

In its response to Request Part 1e, the applicant stated that of the 55 CRDM nozzles with thermal sleeves, only the center 9 (penetration nozzles P1 - P9) on each unit are within the UT examination volume of the reactor vessel head. The applicant also stated that the thermal sleeve centering pads are at the same height approximately 23 in. below the top of the CRDM adapter on each of the CRDM nozzles.

In its response to Request Part 2, the applicant stated that there are no other types of reactor vessel head penetration nozzles affected by loss of material due to wear.

In its response to Request Part 3, the applicant stated that it is planning to manage loss of material of the CRDM nozzles due to thermal sleeve centering pad wear by an analysis evaluating future operation without any required examinations. The applicant also stated that Westinghouse is presently developing a bounding analysis for BBS which is expected to allow operation until the end of the period of extended operation. The applicant further stated that this analysis is currently under development for the industry including BBS, and will consider the maximum credible wear depth of 0.1075 in., minimum CRDM nozzle wall thickness, and all applicable design basis loads.

In addition, the applicant stated that the analysis will include a detailed ASME Code evaluation of the CRDM housing with reduced wall thickness using the bounding CRDM loads and transients. The applicant also indicated that the analysis is scheduled to be completed in 2014 and there is confidence, upon completion of the analysis, that the maximum possible penetration nozzle wear of 0.1075 in. will be acceptable for the period of extended operation.

In its response to Request Part 4, the applicant stated that the water couplant issue at Byron Unit 1 was resolved by the development of an improved probe, which was able to provide essentially 100 percent examination coverage during the subsequent inspection in the Fall 2012 Refueling Outage. The applicant also stated that the improved probe contains two sets of transducers for UT examinations, one set for axial flaws and another set for circumferential flaws in comparison with the previously used probe that contained only one set of transducers for circumferential indications.

In its response to Request Part 5, the applicant stated that no additional program enhancements or AMR items are necessary for the aging management of CRDM nozzles for loss of material due to wear. The applicant also stated that the aging management for wear on the CRDM nozzles will be managed as part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (LRA Section B.2.1.1). As part of its response, the applicant stated that Westinghouse is presently developing a bounding analysis for BBS, which is expected to allow operation until the end of the period of extended operation.

In its review of the applicant's response to RAI B.2.1.5-1, the staff noticed that the applicant stated that it is planning to manage the CRDM nozzle wear by an analysis without any required examinations for the period of extended operation. The staff required information to confirm whether the applicant's analysis is based upon an adequate technical basis and whether the analytical results are acceptable for managing the CRDM nozzle wear.

By letter dated June 4, 2014, the staff issued RAI B.2.1.5-1a requesting the following:

- In Part 1 of RAI B.2.1.5-1a, the staff requested that the applicant describe the technical basis of the applicant's analysis and the specific references for the acceptance criteria of the analysis (e.g., ASME Code Section III Edition and paragraphs and current license basis document sections). In addition, as part of the response, the staff requested that the applicant confirm whether the acceptance criteria adequately addresses the design, normal, upset, faulted, testing, and cyclic (i.e., fatigue analysis) conditions in UFSAR Section 3.9 and its subsections.
- In Part 2 of RAI B.2.1.5-1a, the staff requested that upon completion of the analysis, the applicant provide the analytical results, to confirm that the wear indications meet the acceptance criteria discussed in Request Part 1 described above. In addition, if the applicant's analysis finds that the acceptance criteria cannot be met for the maximum possible wear depth of 0.1075 in., clarify whether volumetric examinations will be performed to monitor the wear depths for adequate aging management.
- In Part 3 of RAI B.2.1.5-1a, the staff requested that the applicant provide any necessary updates to the LRA consistent with the applicant's response to Parts 1 and 2 of the RAI (e.g., enhancements to AMPs and revisions to time-limited aging analyses (TLAAs).

By letter dated June 18, 2014, the applicant provided its response to RAI B.2.1.5-1a. In its response to Part 1 of the RAI, the applicant stated that it is participating in the Westinghouse Owners Group project which is expected to provide a detailed analysis justifying that the nozzle wear acceptance criteria can be met for the maximum possible wear depth of 0.1075 in. The applicant also stated that based on the completed feasibility study for this project, preliminary evaluations of the stresses and fatigue usages were performed to determine the approximate wear depth that could be qualified in accordance with ASME Code, Section III, Subsection NB. The applicant further stated that the detailed analysis was scheduled to be completed in October 2014, and the results would be communicated to the staff by the end of November 2014. (The applicant provided these results, along with additional related information, over the period November 2014 through February 2015, as discussed below.)

In its response to Part 2 of the RAI, the applicant stated that the results from the CRDM nozzle wear analysis are expected to confirm that the wear indications meet the acceptance criteria discussed in response to Part 1 of the RAI. The applicant also stated that if the detailed analysis finds that the acceptance criteria cannot be met for the maximum possible wear of

0.1075 in., then it will work with the industry to develop an approved method of volumetrically examining the wear area of the CRDM housing.

In its response to Part 3 of the RAI, the applicant stated that it is expected that there will be no changes in the LRA resulting from the above mentioned analysis.

By letter dated September 4, 2014, the applicant provided an update to its response to RAI B.2.1.5-1a. The applicant stated that Westinghouse (the vendor performing the analysis) has confirmed that the analysis, when completed, will provide assurance that the CRDM penetration nozzles at BBS will be qualified for continue use. The applicant also stated that it will provide the results of this analysis to the staff in November of 2014. The applicant further stated that in the event the analysis does not support continued operation of the CRDM penetration nozzles, or if the staff finds the analysis unacceptable, then the applicant will provide a commitment to repair or replace the CRDM nozzles at BBS.

The staff identified this issue as Open Item (OI) 3.0.3.1.3-1.

By letter dated November 24, 2014, the applicant provided a brief summary of its analysis and stated that the analysis confirmed that the postulated maximum possible projected wear was acceptable for continued service through the period of extended operation. In this RAI response, the applicant also stated that it would perform its own review to determine if the LRA needs to be revised based on the results of the detailed analysis. Because the applicant's summary description of its analysis did not include detailed information for the staff to review for determining the acceptability of the analysis, the applicant provided the staff access to its proprietary analysis on December 17, 2014.

By letter dated January 28, 2015, the applicant further stated that it completed a thorough review of the analysis and the impact of the completed wear analysis on the LRA. The applicant also stated that it will revise its license renewal commitment list to include an additional commitment which would add the wear analysis into the Byron and Braidwood licensing basis prior to the period of extended operation (Commitment No. 49). The applicant further stated that its review did not reveal any additional changes to the LRA.

Based on staff's review of the applicant's proprietary analysis on CRDM nozzle wear, the staff prepared a number of questions related to the analysis in the form of Draft RAI B.2.1.5-1b. During a teleconference call held on January 29, 2015 (summarized in Agencywide Documents Access and Management System (ADAMS) ML15033A059), the staff and the applicant discussed Draft RAI B.2.1.5-1b. In this discussion, the applicant proposed to submit an amendment to the LRA, which would require performing ultrasonic examinations of the CRDM nozzles; thereby the applicant would perform inspections to justify the continued use of the CRDM nozzles.

In its letter dated February 11, 2015, the applicant revised the LRA Sections A.2.1.1 and B.2.1.1 to include an enhancement to the ASME Section XI Inservice Inspection (ISI) program to include additional NDEs of the five centermost CRDM nozzles. The applicant also provided detailed NDE procedures it will implement prior to and during the period of extended operation to manage the CRDM wear. Based on the new enhancement, the applicant also deleted Commitment No. 49 from the LRA, which was previously described in its letter dated January 28, 2015.

In its February 11, 2015, letter, the applicant further stated that it will utilize a special UT probe (a blade probe) for the inspections, due to the narrow gap between the CRDM nozzle and the thermal sleeve. The applicant also indicated that the applicant's examination method uses increased flow of water couplant for reliable UT of CRDM nozzles with wear degradation. The applicant further stated that this method of examination was qualified by demonstration in accordance with a qualification protocol developed by the Materials Reliability Program (MRP-331, "Qualification Protocol for Pressurized Water Reactor Upper Head Penetration Ultrasonic Examinations"). The applicant stated that the examination was demonstrated to detect, locate, and size indications that initiate either from the inner or outer diameter of the nozzle, as well as measure the depth of the wear.

The applicant stated that each of the units will have the five centermost CRDM nozzles examined once before the period of extended operation. In addition, the applicant also stated that the examinations will continue for each ISI period during the period of extended operation.

The staff finds the applicant's response, including its proposal, acceptable because (1) the applicant confirmed that it will perform periodic volumetric examinations using a qualified method to ensure that the CRDM nozzle wear does not affect the RCPB integrity and (2) the applicant appropriately revised LRA Sections A.2.1.1 and B.2.1.1 consistent with its responses as discussed above. The staff's concerns described in RAIs B.2.1.5-1 and B.2.1.5-1a are resolved and OI 3.0.3.1.3-1 is closed.

As discussed above, the staff noticed that the applicant performed UT examinations of the CRDM nozzles at Byron Station, Unit 1, in 2011, in accordance with ASME Code Case N-729-1. The staff also noticed that the UT examination found that CRDM nozzle Nos. 4 and 8 experienced wear as a result of the interactions between CRDM nozzles and CRDM nozzle thermal sleeves. The staff further noticed that LRA Table 3.1.2-2 indicates that the thermal sleeves of reactor vessel head nozzles are subject to loss of material due to wear. Furthermore, the staff noticed that the thermal sleeves of reactor vessel head nozzles perform the following functions which significantly contribute to safety: (1) shielding the nozzles from thermal transients, (2) providing a lead-in function for the rod cluster control assembly (RCCA) drive rods into the CRDM nozzles, and (3) protecting the RCCA drive rods from the head cooling spray cross flow in the reactor vessel upper head plenum. However, it was not clear to the staff how the applicant will monitor and manage loss of material due to wear of the reactor vessel head nozzle thermal sleeves.

By letter dated December 12, 2013, the staff issued RAI B.2.1.5-2 requesting that the applicant describe for each unit which reactor vessel head nozzles have a thermal sleeve that is subject to loss of material due to wear. The staff also requested that the applicant clarify how loss of material due to wear will be monitored and managed for these thermal sleeves. The staff further requested that, as part of the response, the applicant describe the inspection method, scope, and frequency of the examinations for managing loss of material for the reactor vessel head nozzle thermal sleeves.

By letter dated January 13, 2014, the applicant provided its response to RAI B.2.1.5-2. In its response, the applicant stated that there are a total of 78 CRDM nozzles in the reactor vessel head on each unit with 55 CRDM nozzles having thermal sleeves. The applicant also stated that these 55 locations include 53 penetrations with control rod drive assemblies and two (2) penetrations with reactor vessel level instrumentation system (RVLIS) for removable heated junction thermocouples.

In its response regarding inspections, the applicant stated that wear on the thermal sleeves was first noted in 2007 at a Westinghouse plant. The applicant also stated that Westinghouse issued Technical Bulletin, TB-07-2, "Reactor Vessel Head Adapter Thermal Sleeve Wear," requiring examination of the thermal sleeves in the outer two concentric rows on the reactor vessel head. The applicant further stated that an engineering evaluation was performed that determined the minimum wall thicknesses to maintain thermal sleeve structural integrity at BBS. In addition, the applicant stated that this evaluation included a worst-case analysis for the maximum wear that could be expected on the thermal sleeves.

The applicant stated that this analysis on thermal sleeve wear addressed the failure effects including a complete separation of the thermal sleeve. The applicant also stated that based on the current examination results at BBS, none of the evaluated thermal sleeve indications approach the minimum wall thickness (i.e., 0.061 in.), and no thermal sleeves are expected to separate on any rodded (53) or RVLIS (2) penetration. The applicant further stated that the evaluation also determined that rod drop times would be maintained within the rod drop time technical specification (TS) limit, even with a complete separation of a thermal sleeve.

In addition, the applicant stated that even though the initial recommended scope of thermal sleeve visual inspections in accordance with the Technical Bulletin was the outer two concentric rows (34) on each unit at BBS, all 55 thermal sleeves were examined visually for loss of material due to wear at each unit. The applicant stated that as a result of the initial visual examinations, the five (5) thermal sleeves with the worst wear were selected to be examined with UT in order to obtain measurements of the wear indications. The applicant also stated that the scope of examinations per unit is to perform UT examination of these five leading thermal sleeves with the worst wear found to date. The applicant further stated that the plan for managing thermal sleeve wear is to obtain measured (UT) wear data points on each unit at the designated five thermal sleeve locations during three different outages when reactor vessel head penetration weld examinations are performed and the frequency of the weld examinations is calculated based on ASME Code Case N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds Section XI, Division 1."

Furthermore, the applicant stated that the inspection frequency for the reactor vessel head thermal sleeve loss of material due to wear will be re-evaluated after the accumulation of the three data points on the five worst thermal sleeves. The applicant also indicated that using the guidance provided in Westinghouse Commercial Atomic Power (WCAP)-16911-P, the calculation of future inspection frequencies will be based on the operational time extension curve methodology (i.e., wear rate determination), which utilizes nonlinear dynamic analysis techniques to project wear progression. The applicant further stated that these nonlinear dynamic analysis techniques are incorporated to analyze the variation in wear rate as the clearances at the centering pads increase. Finally, the applicant stated that based on the results obtained from the calculations, the required frequency will be determined for the next inspections and the applicant will implement the examination schedule in accordance with the WCAP-16911-P as described above.

In its review of applicant's response to RAI B.2.1.5-2, the staff found that clarification is necessary on the locations of thermal sleeve wear to confirm whether the initial visual examinations were capable of determining the worst wear indications. In addition, the staff needed clarification on the absence from the response of revisions to the UFSAR supplement (LRA Section A.2.1.1) for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to identify the inspections of the thermal sleeves, consistent with the applicant's response to RAI B.2.1.5-2.

By letter dated June 4, 2014, the staff issued RAI B.2.1.5-2a requesting the following:

- In Part 1 of RAI B.2.1.5-2a, the staff requested the applicant describe the locations of the thermal sleeve wear, to confirm that the initial visual examinations were capable of detecting the worst wear indications.
- In Part 2 of RAI B.2.1.5-2a, the staff requested that the applicant justify why the applicant's response does not include revisions to the UFSAR supplement (LRA Section A.2.1.1) to identify the additional inspections of the thermal sleeves. Alternatively, revise the UFSAR supplement to identify the additional inspections of the thermal sleeves.

By letter dated June 18, 2014, the applicant provided its response to RAI B.2.1.5-2a. In its response to Part 1 of the RAI, the applicant stated that the wear indications on the thermal sleeves are located in the area where the thermal sleeve exits the CRDM head adapter tube (i.e., CRDM housing) inside the reactor vessel. The applicant also stated that since this location is made visible when the reactor vessel head is removed, the visual examinations were capable of detecting the worst wear indications. The applicant further stated that the wear on the thermal sleeves at this location is attributed to the thermal sleeve contacting the inside diameter of the CRDM head adapter tube due to a flow-induced impact rotational motion of the thermal sleeve. In addition, the applicant stated that these wear indications were discovered while the J-groove weld examinations were being conducted.

In its response, the applicant also stated that as a result of similar findings at other PWR units, Westinghouse issued Technical Bulletin, TB-07-02, "Reactor Vessel Head Adapter Thermal Sleeve Wear," to inspect the thermal sleeve wear on the outer two concentric rows of the CRDM housings. The applicant further stated that all BBS units conducted visual examinations on all thermal sleeves, and determined which five thermal sleeves at each unit had the most wear. The applicant clarified that these five designated thermal sleeves at each of Byron Units 1 and 2, and Braidwood Unit 2 had UT examinations performed to measure for wear depth. The applicant also confirmed that UT examinations of Braidwood Unit 1 CRDM thermal sleeves are scheduled to be performed in the Spring 2015 Refueling Outage. In addition, the applicant stated that the UT examinations performed so far for the three units, confirmed that the worst wear occurred within the outermost two concentric rows of CRDMs, as identified in the Westinghouse Technical Bulletin and WCAP-16911-P.

In its response to Part 2 of the RAI, the applicant revised LRA Sections B.2.1.1 (program description) and A.2.1.1 (UFSAR supplement) for the ISI program to reflect the inspection of CRDM thermal sleeves. The applicant's revisions state:

> The control rod drive mechanism (CRDM) thermal sleeves are examined under an augmented ISI inspection program. The scope of examination is to ultrasonically test (UT) the five (5) thermal sleeves with the worst wear on each unit. The plan for managing thermal sleeve wear is to obtain measured (UT) wear data points on each unit at the five (5) designated thermal sleeve reactor core locations during three (3) different outages. The frequency for inspection of the reactor vessel head thermal sleeve for loss of material due to wear will be re-evaluated after the accumulation of the three (3) data points on each of the

> five (5) designated thermal sleeves. The three (3) series of examinations will be performed prior to the period of extended operation. Subsequently, the required frequency for further inspections, if required, will be determined using the guidance provided in WCAP-16911-P, 'Reactor Vessel Head Thermal Sleeve Wear Evaluation for Westinghouse Domestic Plants.'

The staff finds the applicant's response acceptable because (1) the applicant clarified that since the locations of CRDM thermal sleeve wear are visible, the visual examinations of the thermal sleeves can determine the thermal sleeves with the worst wear that will be further examined using UT for adequate aging management of wear, and (2) the applicant appropriately revised LRA Sections B.2.1.1 and A.2.1.1 to include the augmented visual and UT examinations of the thermal sleeves prior to the period of extended operations. The staff's concerns described in RAIs B.2.1.5-2 and B.2.1.5-2a are resolved.

UFSAR Supplement. LRA Section A.2.1.5 provides the UFSAR supplement for the applicant's Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1.

Conclusion. On the basis of its audit and its review of the applicant's Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff also finds that the augmented inservice inspections for the CRDM nozzles and thermal sleeves are acceptable to manage loss of material due to wear for these components. 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 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Summary of Technical Information in the Application. LRA Appendix B, Section B.2.1.6 describes the Thermal Aging Embrittlement of CASS Program as a new program that is consistent with GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." This program will include a screening methodology to determine component susceptibility to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite, consistent with GALL Report AMP XI.M12. This program will provide for either enhanced visual inspections, qualified UT inspections, or flaw tolerance evaluations of susceptible CASS components. Flaw tolerance evaluations will be based on specific geometry and stress information to verify that the CASS material susceptible to thermal aging embrittlement has adequate fracture toughness throughout the period of extended operation. The Thermal Aging Embrittlement of CASS AMP will monitor the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M12. For the "scope of program" and “acceptance criteria” program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs as discussed below.

The “scope of program” and “acceptance criteria” program elements of GALL Report AMP XI.M12 state that the program manages loss of fracture toughness in potentially susceptible ASME Code Class 1 piping components made of CASS. In its review, the staff noticed that LRA Table 3.1.2-2 identifies both CASS and noncast stainless steel (SS) as the materials used to fabricate reactor vessel control rod assembly components, which include latch housing, rod travel housing, cap, and CRDM adapter. However, the staff noticed that the LRA does not provide any additional specific information on the materials used to fabricate these different components of the control rod assembly. In contrast to the LRA, the staff further noticed that the applicant’s UFSAR, Section 15.4.8.1.1, “Design Precautions and Protection” states that the latch mechanism housing and rod travel housing are each a single length of forged Type 304 SS.

By letter dated December 12, 2013, the staff issued RAI B.2.1.6-1 requesting that the applicant clarify which components of the control rod assembly are made of CASS to ensure that all of the Class 1 CASS components are appropriately identified in the scope of the applicant’s program.

In its response dated January 13, 2014, the applicant stated that its control rod assembly is defined as a control rod mechanism (CRDM) and CRDM adapter. The applicant also stated that a CRDM has three pressure-retaining components; the latch housing, rod travel housing, and cap. The applicant further clarified that the only control rod assembly components made of CASS are the latch housings and these latch housings are appropriately identified in the scope of the Thermal Aging Embrittlement of CASS Program.

In addition, the applicant described the materials used to fabricate the control rod assembly components as follows: (1) forged type 304 SS and centrifugally-cast, low-molybdenum SS were used to fabricate the latch housings, and (2) forged type 304 SS was used to fabricate the rod travel housings, the caps, and the CRDM adapters.

In its response, the applicant also clarified that some of the information in the UFSAR Section 15.4.8.1.1 and Table 5.2-2 for the CRDM components is incorrect. The applicant stated that the issue of the incorrect information in the UFSAR has been entered into its CAP.

The staff finds the applicant’s response acceptable because the applicant has clarified that (1) the latch housing is the only CASS component of the control rod assembly, (2) the CASS latch housings are appropriately included within the scope of the applicant’s Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program and are listed in LRA Table 3.1.2-2, item 3.1.1-50, and (3) the issue of the incorrect information on CRDMs in the UFSAR has been entered in the applicant’s CAP. The staff’s concern described in RAI B.2.1.6-1 is resolved.

In addition, the staff noticed that the “acceptance criteria” program element of GALL Report AMP XI.M12 states that flaw tolerance evaluation for components with ferrite content up to 25 percent is performed in accordance with the principles associated with ASME Code, Section XI, IWB-3640 for submerged arc welds. The GALL Report also states that flaw tolerance evaluation for piping with greater than 25 percent ferrite is performed on a case-by-case basis by using the applicant’s fracture toughness data. The staff also noticed that the LRA does not address whether the applicant has any susceptible CASS components with ferrite content greater than 25 percent. In addition, the LRA does not clearly address whether the flaw tolerance evaluation for susceptible CASS components with greater than 25 percent ferrite will be performed on a case-by-case basis with relevant fracture toughness data.

By letter dated December 12, 2013, the staff issued RAI B.2.1.6-2 requesting that the applicant clarify whether it has any susceptible CASS components with ferrite content greater than 25 percent. In addition, the staff requested that, if there are any susceptible CASS components with ferrite content greater than 25 percent, the applicant provide the following: (1) component name, (2) casting method and material grade, (3) ferrite content, either measured or calculated, and (4) clarification as to whether the applicant's flaw tolerance evaluation will be performed on a case-by-case basis using relevant fracture toughness data, and (5) applicant's methodology to be used in the flaw tolerance evaluation and the technical basis for the methodology.

In its response dated January 13, 2014, the applicant stated that there are no susceptible CASS ASME Class 1 components with calculated ferrite content greater than 25 percent using the Hull's equivalent factors. The applicant also stated that ASME Class 1 components fabricated of CASS consist of the reactor coolant pipe fittings (elbows) and some of the CRDM latch housings (i.e., 35 CASS latch housings of total 53 latch housings). The applicant further stated that low molybdenum CASS was used for both CASS components. In addition, the applicant stated that the reactor coolant pipe fittings were statically cast and the ferrite content of the components, as determined using the Hull's equivalent factors, was less than 25 percent. The applicant also clarified that the CRDM latch housings were centrifugally-cast, and were determined to be nonsusceptible to thermal aging embrittlement based on the low-molybdenum-content and casting method of the components.

The staff finds the applicant's response acceptable because the applicant has clarified that it does not have any susceptible CASS ASME Code Class 1 components with ferrite content greater than 25 percent. The staff's concern described in RAI B.2.1.6-2 is resolved.

Based on its audit and its review of the applicant's LRA and responses to RAIs B.2.1.6-1 and B.2.1.6-2, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M12.

<u>Operating Experience</u>. LRA Section B.2.1.6 summarizes OE related to the Thermal Aging Embrittlement of CASS Program. However, the staff noticed that LRA Section B.2.1.6 does not provide any OE that is specifically related to the CASS control rod assembly components and reactor coolant pipe fittings (elbows). By letter dated December 12, 2013, the staff issued RAI B.2.1.6-3, requesting that the applicant provide OE specific to the CASS control rod assembly components and reactor coolant fittings, including any relevant inspection results.

In its response dated January 13, 2014, the applicant stated that the CASS components in its Thermal Aging Embrittlement of CASS Program are ASME Class 1 components and are currently monitored and managed by the ASME Section XI ISI program. The applicant also stated that previous examinations during past inspection intervals included Visual Testing (VT-2) and ultrasonic examinations for the welds of CASS pipe fitting to forged pipe and nozzle safe ends. The applicant further stated that the examinations of these components did not identify any conditions that exceeded the applicable acceptance standards.

The staff finds the applicant's response acceptable because (1) the applicant has provided the OE specific to its CASS components, including the results of the visual examinations during pressure testing as well as the volumetric examinations of the welds for CASS pipe fittings and

(2) the applicant has confirmed that these examinations did not identify any conditions that exceeded the applicable acceptance standards. The staff's concern described in RAI B.2.1.6-3 is resolved.

The staff also reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, and review of the applicant's response to RAI B.2.1.6-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which the GALL Report AMP XI.M12 was evaluated.

UFSAR Supplement. LRA Section A.2.1.6 provides the UFSAR supplement for the Thermal Aging Embrittlement of CASS Program. The staff reviewed this UFSAR supplement description of the program and finds that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noticed the applicant committed to implement the new Thermal Aging Embrittlement of CASS Program prior to the period of extended operation for managing the effects of aging for the ASME Code Class 1 CASS components. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Thermal Aging Embrittlement of CASS Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions(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 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 GALL Report AMP XI.M17, "Flow-Accelerated Corrosion." The LRA states that the AMP is based on implementation of EPRI guidelines in NSAC-202L-R3, "Recommendations for an Effective Flow Accelerated Corrosion Program," and addresses carbon steel piping and heat exchanger components exposed to treated water, closed cooling water, and steam environments. The LRA also states that the AMP proposes to manage wall thinning due to flow-accelerated corrosion through periodic inspections using ultrasonic, visual, or other approved testing techniques and that program activities include analyses, where applicable, to determine critical locations using CHECWORKS™, and evaluations of inspection data to calculate wear, wear rate, and remaining life using a computer program, such as Flow-Accelerated Corrosion Manager. The LRA further states that corrective action, such as repair, replacement, or re-evaluation, is required if a component's remaining life cannot be shown to be more than one operating cycle.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M17. For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

As currently implemented at Byron and Braidwood, the Flow-Accelerated Corrosion Program manages components made from materials other than carbon steel, which are not susceptible to flow-accelerated corrosion. In addition, it manages components that are subjected to non–flow-accelerated corrosion wall-thinning mechanisms such as droplet impingement. Both aspects are inconsistent with the GALL Report AMP XI.M17. It was not clear to the staff whether the applicant intends to modify its current Flow-Accelerated Corrosion Program by using another AMP to manage these non–flow-accelerated corrosion–susceptible materials and non–flow-accelerated corrosion mechanisms, or whether the applicant will modify its LRA to reflect the materials and aging mechanisms that are currently being managed by the Flow-Accelerated Corrosion Program. In addition, the staff noticed that the applicant's subtier procedures for ER-AA-430, "Conduct of Flow-Accelerated Corrosion Activities," included a procedure to manage erosion titled: ER-AA-430-1004, "Erosion in Piping and Components Guide." It was not clear to the staff whether the applicant's flow-accelerated corrosion activities included management of erosion in piping, which is not consistent with the GALL Report AMP. By letter dated April 17, 2014, the staff issued RAI B.2.1.8-1 requesting the applicant to clarify these issues.

In its response dated May 15, 2014, the applicant stated that the Byron and Braidwood sites implemented Exelon procedure ER-AA-43-1004 in October 2013, after the LRA was submitted. The applicant also stated that it updated the Flow-Accelerated Corrosion Program to credit the procedure, thereby implementing the recommendations of LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms." Consequently, the applicant revised LRA Tables 3.1.2-4, 3.3.2-2, and 3.4.2-5 and LRA Sections A.2.18 and B.2.1.8 to reflect that the program also manages wall thinning due to mechanisms other than flow-accelerated corrosion. The staff finds the applicant's response acceptable because the revised program now reflects the materials and aging mechanisms being managed by the Flow-Accelerated Corrosion Program, which is also consistent with the approach provided in LR-ISG-2012-01. The staff's concerns described in RAI B.2.1.8-1 are resolved.

For the "scope of program" program element, the GALL Report AMP XI.M17 states that the program relies on the guidelines in NSAC-202L and includes administrative controls to assure that structural integrity is maintained. NSAC-202L states that corporate commitment is essential to an effective Flow-Accelerated Corrosion Program and recommends that this includes ensuring appropriate QA is applied. In addition, NSAC-202L also recommends that several aspects of the program be independently checked, including the susceptibility analysis, the predictive plant model, the selection of inspection locations, and component structural evaluations. The staff noticed that Byron and Braidwood use the software programs CHECWORKS™ and Flow-Accelerated Corrosion Manager, and although both are currently validated and verified, their classification through IT-AA-101, "Digital Technology Software Quality Assurance Procedure," does not require (or suggest) validation and verification activities for these software programs. The staff also noticed that current program activities require independent verification of some documentation; however, there did not appear to be any guidance relating to independent verification of the predictive plant model. By letter dated April 17, 2014, the staff issued RAI B.2.1.8-2 requesting the applicant to clarify these issues.

In its response dated May 15, 2014, the applicant clarified that it replaced the Flow-Accelerated Corrosion Manager software with IDDEAL® software and that both CHECWORKS™ and IDDEAL® are verified and validated prior to placing them into production. The applicant also stated that it will enhance the program procedures to require documentation of the validation and verification for any updated versions of flow-accelerated corrosion–related software prior to use. In addition, the applicant provided Exelon's procedural requirements for independent checks of the various flow-accelerated corrosion–related activities, including the CHECWORKS™ predictive models, as recommended by NSAC-202L, Section 3.3. The staff finds the applicant's response acceptable because current program procedures require that updates to the predictive models are controlled and independently reviewed by a second qualified flow-accelerated corrosion engineer, consistent with NSAC-202L recommendations. In addition, the program procedures will be enhanced to require documentation of the validation and verification for any updated versions of flow-accelerated corrosion–related software prior to use. The staff's concerns described in RAI B.2.1.8-2 are resolved.

<u>Enhancement 1</u>. LRA Section B.2.1.8, as modified by letter dated May 15, 2014, includes an enhancement to require the documentation of the validation and verification of updated vendor-supplied flow-accelerated corrosion–related software that calculates component wear, wear rates, remaining life, and next scheduled inspection. The staff reviewed this enhancement as part of its evaluation of the applicant's response to RAI B.2.1.8-2, above, and finds it acceptable because when implemented the program will verify that appropriate QA activities related to validation and verification of updated software will be consistent with the recommendations in NSAC-202L-R3.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.8-1 and B.2.1.8-2, the staff finds that program elements 1 through 6, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M17.

<u>Operating Experience</u>. LRA Section B.2.1.8 summarizes OE related to the Flow-Accelerated Corrosion Program. For Byron, the LRA describes flow-accelerated corrosion examinations in 2007 that identified wall thinning in a 3-in. second stage reheater vent line that resulted in several inspection scope expansions due to identification of additional thinned piping. The LRA states that this eventually led to the replacement in 2008 of all Unit 2A moisture separator reheater second stage vent lines with flow-accelerated corrosion–resistant material, demonstrating that the Flow-Accelerated Corrosion Program effectively monitors components and takes corrective actions, including extent of condition, prior to loss of intended function. For Braidwood, the LRA describes flow-accelerated corrosion inspections in 2011 for the 42-in. cross-under pipes between the high pressure turbine and 2B moisture separator reheater that identified undercut areas at the interface between the pipe and turning vane assemblies. The LRA states that undercut areas were repaired prior to restart, demonstrating that the Flow-Accelerated Corrosion Program identifies and implements effective corrective measures prior to loss of intended function.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff identified OE for which it determined the need for additional clarification with respect to the program's use for managing non–flow-accelerated corrosion mechanisms and components constructed of materials that are not susceptible to flow-accelerated corrosion. These inconsistencies with GALL Report AMP XI.M17 are addressed above.

Based on its audit, and its review of the application and the applicant's response to RAI B.2.1.8-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M17, as modified through LR-ISG-2012-01, was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.8, as modified in its responses to RAI B.2.1.8-1 and RAI B.2.1.8-2, provides the UFSAR supplement for the Flow-Accelerated Corrosion Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, as modified through LR-ISG-2012-01. The staff also noticed that the applicant committed to ongoing implementation of the existing Flow-Accelerated Corrosion Program and to implement the enhancement to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by letter dated May 15, 2014, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's Flow-Accelerated Corrosion Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 One-Time Inspection

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.20 describes the new One-Time Inspection Program as consistent with GALL Report AMP XI.M32, "One-Time Inspection." The One-Time Inspection Program will be used to verify the system-wide effectiveness of the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs, which are designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation. The program will also be utilized, in specific cases where existing data is insufficient, to verify that a particular aging effect does not occur, or to verify that the aging effect is occurring slowly enough to not affect components' intended functions during the period of extended operation. The program manages loss of material, cracking, and reduction of heat transfer in piping, piping components, piping elements, tanks, pump casings, heat exchangers, and other components within the scope of license renewal for outdoor air, fuel oil, lubricating oil, reactor coolant, steam, treated water, and treated borated water environments. The program identifies inspections focused on locations that are isolated from the flow stream, are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M32.

The staff noticed that, in letters dated January 13, 2014, July 18, 2014, and August 29, 2014, the applicant revised LRA Sections A.2.1.20 and B.2.1.20 to include inspections for cracking of insulated and uninsulated SS and aluminum components exposed to outdoor air in the One-Time Inspection Program. The staff's evaluation of these activities is documented in its evaluation of the External Surfaces Monitoring of Mechanical Components Program in SER Section 3.0.3.1.9.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M32.

Operating Experience. LRA Section B.2.1.20 summarizes OE relevant to the One-Time Inspection Program. In 2005, Byron personnel drained, cleaned, and visually inspected the fuel oil day tank associated with the 2B auxiliary feedwater (AFW) diesel pump, as part of its scheduled periodic inspection. The inspection identified a thin layer of dark brown material coating the interior of the tank, and this finding was entered into the CAP. The source or cause of the coating was never determined, and the inspection revealed no evidence of age-related degradation. The corresponding Unit 1 fuel oil day tank had been inspected earlier that year with no deficiencies noted. In 2011, Braidwood personnel performed a UT examination on an 8-in. pipe in the Unit 2 RHR system, in accordance with the requirements for MRP-192, "Assessment of RHR Mixing Tee Thermal Fatigue in PWR Plants." The examination found a 0.7 in. long indication 43 percent through-wall. The cause of the indication was attributed to a manufacturing defect, and the flaw analysis showed that the indication in the mixing tee weld met the requirements of ASME Section XI, IWB-3500. Engineering evaluated the condition and justified continued operation until repairs, scheduled for spring 2014, are completed. The applicant stated that the inspection techniques and methods for the OE examples in the LRA are the same as those to be used by the new One-Time Inspection Program and have been proven effective in detecting cracking, loss of material, and reduction of heat transfer.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M32 was evaluated.

UFSAR Supplement. LRA Section A.2.1.20, as amended by letter dated August 29, 2014, provides the UFSAR supplement for the One-Time Inspection Program. The staff reviewed this UFSAR supplement description of the program and found that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the new One-Time Inspection prior to the period of extended operation and to perform the one-time inspections within the 10-year period prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

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

3.0.3.1.7 Selective Leaching

Summary of Technical Information in the Application. LRA Section B.2.1.21 describes the new Selective Leaching program as consistent with GALL Report AMP XI.M33, "Selective Leaching." The LRA states that the AMP addresses gray cast iron and copper alloy with greater than 15 percent zinc piping and fittings, valve bodies, pump casings, heat exchanger components, and structural members exposed to raw water, closed-cycle cooling water, outdoor air (Byron only), and waste water. There are no aluminum bronze in-scope components with greater than 8 percent aluminum in any environment. The AMP includes visual examinations, supplemented by hardness measurement or other appropriate examination methods, of a representative sample of components (20 percent of susceptible components with a maximum of 25 inspections for each susceptible material and environment combination group) to determine whether loss of material due to selective leaching is occurring.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M33.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M33.

Operating Experience. LRA Section B.2.1.21 summarizes OE related to the Selective Leaching program. At Byron, the applicant did not identify any instances of selective leaching. However, at Braidwood, the applicant identified one instance of selective leaching on a component that is not within the scope of license renewal. In June 2005, a brass fitting on a supply line to a toilet in the New Training Building was sheared off the wall. Based on a metallurgical analysis, Exelon Power Labs determined that the fitting had undergone dezincification. The LRA states that there have been no indications of selective leaching in any in-scope systems at Braidwood.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M33 was evaluated.

UFSAR Supplement. LRA Section A.2.1.21 provides the UFSAR supplement for the Selective Leaching program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to conduct one-time inspections of a representative sample of susceptible components to determine if a loss of material due to selective leaching is occurring within the 5-year period prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

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

3.0.3.1.8 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B.2.1.22 describes the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as consistent with GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping." The applicant stated that this program is a new "conditioning monitoring" program that will manage cracking of piping in a reactor coolant environment. It also stated that the program will perform one-time inspections of a sample of ASME Code Class 1 piping less than nominal pipe size four (4) in. (NPS 4) and greater than or equal to one (1) in. (NPS 1) that includes pipes, fittings, branch connections, and full and partial penetration welds. The applicant further stated it has not experienced cracking of ASME Code Class 1 small-bore piping due to intergranular stress corrosion or fatigue at Byron and Braidwood Units 1 and 2. In addition, the applicant stated that for socket weld examinations, volumetric examinations are performed using a demonstrated technique that is capable of detecting cracking. The applicant stated that if such volumetric techniques are not available by the time of the inspection, the examination method will be by destructive testing. If destructive testing is performed, each examination will be credited as equivalent to having volumetrically examined two socket welds. The applicant further stated that the program's sampling approach is based on susceptibility to stress corrosion, cyclic loading (including thermal, mechanical, and vibration fatigue), thermal stratification, thermal turbulence, dose considerations, OE, and limiting locations of the total population of ASME Class 1 small-bore piping.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared elements 1 through 6 of the applicant's program to the corresponding elements of GALL AMP XI.M35.

The applicant stated that the program provides a one-time volumetric or opportunistic destructive inspection for butt welds consisting of a 10-percent sample or a maximum of up to 25 ASME Class 1 piping butt weld locations and for socket welds consisting of a 10-percent or a sample of up to 25 ASME Class 1 socket weld locations that are susceptible to cracking for each unit at BBS.

During the review, the staff noticed that LRA Sections A.2.1.22 and B.2.1.22 do not provide the specific population of in-scope butt welds and socket welds. Therefore, the staff needed additional information to determine the inspection sample size for butt welds and socket welds.

By letter dated December 12, 2013, the staff issued RAI B.2.1.22-2 requesting that the applicant provide the total population and the inspection sample size for each weld type (e.g., butt welds and socket welds) for each unit (i.e., Byron Units 1 and 2, and Braidwood Units 1 and 2). In addition, the staff requested that the applicant update LRA Sections A.2.1.22 and B.2.1.22 as appropriate and in accordance with its response to RAI B.2.1.22-2.

The applicant responded to RAI B.2.1.22-2 in letter dated January 13, 2014. The applicant stated that at Braidwood, there are 933 ASME Class 1 small-bore socket welds and 136 ASME Class 1 small-bore butt welds for Unit 1, and 962 ASME Class 1 small-bore socket welds and 129 ASME Class 1 small-bore butt welds for Unit 2. At Byron, there are 872 ASME Class 1 small-bore socket welds and 175 ASME Class 1 small-bore butt welds for Unit 1, and 828 ASME Class 1 small-bore socket welds and 181 ASME Class 1 small-bore butt welds for Unit 2. The applicant also specified its inspection sample size which will include 10 percent of the socket weld population up to a maximum of 25 socket welds for each Byron and Braidwood unit and 10 percent of the butt weld population up to a maximum of 25 butt welds for each Byron and Braidwood unit, as consistent with the GALL report guidance. In addition, the applicant revised the LRA Appendix A, Section A.2.1.22, and Appendix B, Section B.2.1.22 to reflect the changes.

The staff noticed that the applicant's response provided specific information on ASME Class 1 small-bore piping weld populations for butt welds and socket welds at Byron and Braidwood for both Unit 1 and Unit 2. The staff also noticed that the inspection sample size is consistent with the GALL report guidance for each of the applicant's units. The staff finds the applicant's response acceptable because (1) the applicant has provided specific weld population in the "scope of program" program element, (2) its sample size is consistent with the guidance provided in the GALL Report AMP XI.M35, which recommends that the inspection should include 10 percent of the weld population or a maximum of 25 welds for each weld type for each unit, and (3) the applicant has amended LRA Appendix A, Section A.2.1.22, and Appendix B, Section B.2.1.22, consistent with its response to RAI B.2.1.22-2. Therefore, the staff's concerns expressed in RAI B.2.1.22-2 are resolved.

The staff noticed that the applicant will implement a risk-informed methodology for sample selection to ensure the most susceptible and risk-significant welds are selected. The "detection of aging effects" program element of GALL AMP XI.M35 recommends a methodology that selects the most susceptible and risk-significant welds to inspect. The staff finds the sample selection methodology consistent with GALL AMP XI.M35 and, therefore, acceptable.

The staff also noticed that the inspections will be completed within 6 years prior to the period of extended operation. The staff finds the applicant's proposal consistent with GALL AMP XI.M35 regarding timely implementation of the small-bore piping inspections and, therefore, acceptable.

Based on its audit, and review of the applicant's response to RAI B.2.1.22-2, the staff finds that elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M35.

Operating Experience. LRA Section B.2.1.22 summarizes OE related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The LRA discussed plant-specific OE and provided examples relevant to the program.

GALL Report AMP XI.M35 states that the one-time inspection program does not apply to plants that have experienced cracking in ASME Code Class 1 small-bore piping due to stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence. LRA Section B.2.1.22 indicates that Byron and Braidwood have not experienced this type of cracking.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and plant-specific OE were reviewed by the applicant. The staff noticed that the plant-specific OE in the LRA section documented a failure of an ASME Code Class 1 socket weld (an elbow to pipe weld) on a SIS line at Byron Unit 1 in 1998. The applicant attributed the failure to a fabrication flaw. However, based on the limited information provided at the audit, the staff determined that the failure could have been caused by vibration fatigue.

By letter dated December 12, 2013, the staff issued RAI B.2.1.22-1 requesting that the applicant provide information in terms of metallurgical analysis to support whether the failure was caused by “a fabrication flaw,” or vibration fatigue, and that the applicant explain why the one-time inspection program would still be applicable.

In its response dated January 13, 2014, the applicant summarized the OE and concluded that the crack initiated from lack of fusion - “a fabrication flaw,” and probably failed by service-induced fatigue loading. The applicant documented its corrective actions, and also made design changes to mitigate vibration load for the affected components. The applicant performed extent of condition which inspected similar welds but did not detect any indication of leakage. The applicant also stated that there have been no additional failures of ASME Code Class 1 small-bore piping since 1998.

The staff noticed that the applicant has performed design changes to mitigate the cause of failure, and performed additional inspections to determine the extent of condition. In addition, there have been no additional similar failures of ASME Code Class 1 small-bore piping welds since the implementation of the applicant’s corrective actions. In addition, the one-time inspection implemented prior to the period of extended operation should confirm the effectiveness of the applicant’s corrective actions. Therefore, consistent with GALL Report AMP XI.M35, the use of the applicant’s One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is appropriate, because the reported failure of 1998 was successfully mitigated.

As discussed in the Audit Report, the staff conducted an independent search of the applicant’s OE information to determine whether the applicant had adequately incorporated and evaluated OE related to this program. The staff found no OE to indicate that the applicant’s program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and its review of the application, and review of the applicant’s response to RAI B.2.1.22-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which the GALL AMP XI.M35 was evaluated.

UFSAR Supplement. LRA Section A.2.1.22 provides the UFSAR supplement for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1 and finds it consistent with the corresponding program description in SRP-LR. The staff also noticed that the applicant committed to implement the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as described in LRA Section B.2.1.22, which states that the inspections will be conducted within 6 years prior to entering the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended by letter dated January 13, 2014, is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL AMP XI.35. The staff concludes that the applicant 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 External Surfaces Monitoring of Mechanical Components

Summary of Technical Information in the Application. LRA Section B.2.1.23 describes the new External Surfaces Monitoring of Mechanical Components program as consistent with GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." The LRA states that the AMP will manage loss of material in metallic components exposed to air environments through periodic visual inspections. The LRA also states that the AMP will manage hardening and loss of strength of elastomeric components through visual inspections supplemented by physical manipulations.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M36.

For the "scope of program" and "detection of aging effects" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs. The two subject areas of the RAIs are: (1) cracking of uninsulated outdoor components and (2) loss of material and cracking of insulated outdoor components and indoor insulated components operated below the dew point.

(1) *Cracking of Uninsulated Outdoor Components*

The "scope of program" program element in GALL Report AMP XI.M36 recommends that cracking of SS components exposed to an air environment containing halides be managed. During its audit, the staff noticed that the documentation for the applicant's External Surfaces Monitoring of Mechanical Components program states that contaminant deposition by the cooling tower plume is not expected on in-scope components due to the prevailing wind direction at Byron. As a result, cracking is not an aging effect being managed by the program. By letter dated December 13, 2013, the staff issued RAI B.2.1.23-1 requesting that the applicant provide the basis for why the chemical compounds in the cooling tower plume at Byron and potential soil contamination at Braidwood cannot result in SCC on the external surfaces of aluminum and SS components exposed to outdoor air.

In its response dated January 13, 2014, the applicant stated that it has not been demonstrated that environmental halide levels preclude SCC for uninsulated SS piping. As a result, for liquid-filled components, the applicant revised LRA Section B.2.1.23 to include cracking as an aging effect being managed by the External Surfaces Monitoring of Mechanical Components Program. For gas-filled components (e.g., diesel exhaust piping), the applicant stated that the One-Time Inspection Program will be used to assess cracking of SS components exposed to outdoor air for gas-filled components (e.g., diesel exhaust piping). The applicant also added several AMR line items to manage cracking on exposed external surfaces of SS components (i.e., surfaces that are not covered by jacketed insulation or otherwise shielded from the outdoor environment). The staff finds the applicant's response acceptable because (a) the periodic visual inspections of liquid-filled components in the External Surfaces Monitoring of Mechanical Components Program, occurring at least once per refueling cycle, are capable of detecting leakage that is indicative of cracking prior to loss of intended function; and (b) the one-time inspection of diesel exhaust piping can detect discoloration and staining that would be indicative of cracking.

(2) *Loss of Material and Cracking of Outdoor Insulated Components and Indoor Insulated Components Operated below the Dew Point*

The "scope of program" and "detection of aging effects" program elements in GALL Report AMP XI.M36 were revised by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," to include inspections for loss of material and cracking under insulation. Because the LR-ISG was issued after the LRA was submitted, these activities were not initially addressed in the applicant's program. By letter dated December 13, 2013, the staff issued RAI 3.0.3-3 requesting that the applicant address the recommendations in the LR-ISG related to corrosion under insulation for outdoor insulated components and indoor insulated components operated below the dew point.

In its response dated January 13, 2014, the applicant revised the External Surfaces Monitoring of Mechanical Components Program to include periodic inspections to identify corrosion (loss of material) under insulation on a representative sample of components during each 10-year period during the period of extended operation. If the initial inspection does not identify loss of material, subsequent inspections will consist of examination of the exterior surfaces of the insulation for indications of damage or water intrusion. The staff noticed that, for the loss of material aging effect, the applicant's response was consistent with LR-ISG-2012-02.

However, the applicant's RAI response did not include cracking due to SCC as an aging effect for insulated SS and aluminum components on the basis that the jacketed insulation prevents halide intrusion. The staff noticed that, while insulation jacketing may prevent halide intrusion, it was unclear whether the specific jacketing at BBS is an effective barrier. By letter dated April 10, 2014, the staff issued RAI 3.0.3-3a requesting that the applicant provide further justification for why cracking cannot occur on SS and aluminum external surfaces that are covered by jacketed insulation.

In its response dated May 12, 2014, the applicant stated that it will perform a one-time visual inspection of a representative sample of insulated SS and aluminum surfaces to confirm that SCC does not occur. Water-filled piping will be inspected for signs of leakage. Exhaust lines will be inspected for signs of discoloration or staining. The staff finds the applicant's response acceptable because the proposed visual inspections are capable of detecting leakage, discoloration, and staining that would be indicative of SCC occurring under the insulation.

Although the staff found the applicant's approach to manage cracking acceptable, the staff noticed that the applicant did not incorporate details of the cracking inspections into the applicable programs or UFSAR supplements. In telephone conference calls with the applicant on June 30, 2014, and July 30, 2014, the staff discussed its concerns about documenting these inspection activities within the LRA. In letters dated July 18, 2014, and August 29, 2014, the applicant revised LRA Sections A.2.1.20, A.2.1.23, B.2.1.20, and B.2.1.23 for the External Surfaces Monitoring of Mechanical Components and One-Time Inspection Programs to include details of the inspection for cracking. The staff finds that the revised program documents adequately describe the inspection activities.

The staff's evaluations of the individual AMR line items associated with the RAI responses are documented in the appropriate SER sections for those line items.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.23-1, 3.0.3-3, and 3.0.3-3a, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M36, as revised by LR-ISG-2012-02.

Operating Experience. LRA Section B.2.1.23 summarizes OE related to the External Surfaces Monitoring of Mechanical Components Program. The LRA describes coating degradation and general corrosion that was identified on the bottom of the extraction steam header in 2005. The issue was entered in the CAP, which resulted in the pipe's being cleaned, ultrasonically tested to determine the wall thickness, and recoated. The LRA also describes the identification of surface corrosion on the nitrogen accumulator supply and associated piping. The issue was entered into the CAP, which resulted in the piping's being cleaned and repainted.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M36 was evaluated.

UFSAR Supplement. LRA Section A.2.1.23, as revised by letter dated July 18, 2014, provides the UFSAR supplement for the External Surfaces Monitoring of Mechanical Components Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, as revised by LR-ISG-2012-02. The staff also noticed that the applicant committed to implement the new

External Surfaces Monitoring of Mechanical Components Program prior to the period of extended operation for managing the effects of aging for applicable components. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's External Surfaces Monitoring of Mechanical Components Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Flux Thimble Tube Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.24, as revised by letters dated October 31, 2014, November 22, 2014, February 23, 2015, and April 13, 2015, describes the existing Flux Thimble Tube Inspection Program as consistent, with exception and enhancements, with GALL Report AMP XI.M37, "Flux Thimble Tube Inspection." The LRA states that the program manages loss of material in flux thimble tubes due to wear (i.e., wall thinning) in a reactor coolant environment. The LRA also states that eddy current testing is used to periodically inspect the full length of all flux thimble tubes, which encompasses the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide. The program establishes a maximum allowable wall loss of 60 percent before corrective actions are required. The LRA states that, if the wall loss is greater than 60 percent but less than 80 percent, corrective actions include repositioning, isolation, or flux thimble tube replacement. Flux thimble tubes that exhibit wall loss of greater than 80 percent are isolated or replaced. The LRA further states that, if wear rate data indicate that a flux thimble tube will exceed 80 percent wall loss prior to the next scheduled inspection, corrective actions include repositioning, isolation, or flux thimble tube replacement.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M37. Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M37. As discussed below, however, program element 10, "operating experience," for Braidwood, Units 1 and 2, required further staff evaluation before it was found to be acceptable.

By letter dated April 13, 2015, one exception and two enhancements applicable only to Braidwood Station, Units 1 and 2, were identified due to the unique OE at Braidwood Station. The staff's evaluation of the exception and the enhancements is presented in the OE section below.

Operating Experience. LRA Section B.2.1.24 summarizes OE related to the Flux Thimble Tube Inspection program.

Byron OE. The applicant provided plant-specific OE at Byron Unit 1 and stated that the most recent eddy current testing was performed during the fall 2009 refueling outage and is performed on a three-refueling-outage frequency. The inspection results confirmed that there was no wear in its flux thimble tubes that exceeded the specified acceptance criteria and the highest recorded wall loss was only 24 percent. The LRA states that two flux thimble tubes have been removed from service due to an issue other than wear (displaced antivibration sleeves). The LRA further states that this example provides objective evidence that the Flux Thimble Tube Inspection Program implements examinations using appropriate methods and examination frequency recommended in the PWR guidelines.

The applicant also provided plant-specific OE at Byron Unit 2 and stated that the most recent eddy current testing was performed during the fall 2008 refueling outage and is also performed on a three-refueling-outage frequency. The applicant stated that the inspection results confirmed that no flux thimble tube exceeded the specified acceptance criteria, and the highest recorded wall loss was only 26 percent.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions at Byron Units 1 and 2. In addition, the staff finds that the conditions and OE at Byron Units 1 and 2 are bounded by those for which GALL Report AMP XI.M37, “Flux Thimble Tube Inspection,” was evaluated. The staff confirmed that the “operating experience” program element for Byron Units 1 and 2 satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

Braidwood OE. The applicant also provided plant-specific OE for Braidwood Station. The OE included its most recent inspections during the Unit 1 Spring 2012 Refueling Outage and Unit 2 Fall 2011 Refueling Outage. The applicant stated that these inspections confirmed that no flux thimble tube exceeded the specified acceptance wear criteria for wall thickness. However, the applicant’s brief discussion also indicated that a few of the flux thimble tubes had experienced higher wear rates and that the examination frequency for both Braidwood units was changed to every refueling outage due to the observed higher wear rates. The highest detected wear was 49 percent at Unit 1 and 57 percent at Unit 2.

In addition, the staff’s review of the OE indicated that there have been instances when, either because of an obstruction or due to other outage-related work, all the Braidwood flux thimbles were not examined. Furthermore, the staff’s review of the OE data base for Braidwood also revealed that eddy current examinations were not performed during a scheduled inspection for certain flux thimbles due to the presence of moisture in the flux thimble tubes.

By letter dated May 19, 2014, the staff issued RAI B.2.1.24-1 requesting the applicant to:

(1) Provide information in terms of root-cause analyses and corrective actions which can explain and account for the higher than anticipated wear rates for Braidwood Units 1 and 2 flux thimble tubes.

(2) Explain what root-cause analyses and corrective actions have been performed to correct the occurrences of moisture in the thimble tubes, given that these occurrences interfere in eddy current examinations of the flux thimble tubes.

(3) Justify the adequacy of the program if the unexpected high wear rates are not accounted for and mitigated, given that there are issues related to the eddy current examinations of all flux thimble tubes (i.e., conflicting outage schedule, tube blockage, and the presence of moisture in the flux thimbles).

By letter dated June 9, 2014, the applicant provided its response to RAI B.2.1.24-1. In its response to Part 1 of the RAI, the applicant stated that, for Unit 1, higher than anticipated wear rates of 37 percent per cycle and 27 percent per cycle were observed on two of the flux thimble tubes during the Fall 2010 Refueling Outage (these two flux thimble tubes were installed in the Spring 2009 Refueling Outage and replaced the original equipment flux thimble tubes). The applicant stated that the two original flux thimbles had been capped during the Fall 2007 Refueling Outage due to flux thimble tubes being restricted (i.e., full length could not be tested). The applicant also stated that subsequent eddy current testing showed that the location with 27 percent wear in 2010 had no distinguishable wear in 2012. The applicant also stated that the flux thimble tube in the location that experienced 37 percent wear in 2010 had to be replaced in 2012 due to the detector becoming stuck, and therefore, eddy current testing was not performed.

The applicant stated that for Unit 2, a higher than anticipated wear rate of 35 percent per cycle was observed on one flux thimble tube during the Spring 2011 Refueling Outage (the flux thimble tube was installed in the Fall 2009 Refueling Outage and replaced an original equipment flux thimble tube). The applicant also stated that subsequent eddy current testing showed that the location with 35 percent wear in 2011 had 41 percent wear in 2012. The applicant further stated that higher than expected wear rate was observed on another original equipment flux thimble tube, in which the wear went from 36 percent in the Spring 2008 Refueling Outage to 57 percent in the Spring 2011 Refueling Outage, an increase in wear of 21 percent in two operating cycles (previous testing indicated a 3 percent wear rate per cycle).

The applicant stated that the exact cause of the higher than anticipated wear rates has not been determined, but it had increased the inspection frequency to each outage from the previous once every three outages to mitigate the issue. In addition, the issue is not widespread (i.e., only at two locations). The applicant indicated that the observed wear rates were found significantly lower on each affected flux thimble during the second cycle. The applicant also stated that performing eddy current testing each outage might not be justifiable long term, due to the radiological dose concerns, cost, and station resources. Therefore, if subsequent eddy current testing does not support decreasing inspection frequency at these specific locations, these locations could be either abandoned (capped) or the flux thimble tubes replaced since these are the only locations that have experienced higher than anticipated wear.

The staff finds the applicant’s response to Part 1 of the RAI acceptable because (1) the higher flux thimble tube wear rate occurred during the first operating cycle (following its installation), which is not unusual; (2) the applicant has accounted for the higher wear rates by adjusting the frequency of inspections; and (3) the higher wear rates are limited to a few locations; furthermore, if subsequent tests for these limited locations do not support decreasing inspection frequency, these tubes could be either capped or replaced.

In its response to Part 2 of the RAI, the applicant stated that the cause of the moisture in the flux thimble tubes was determined to be condensation due to changes in containment temperature during the time between when the flux thimble tubes are cleaned and dried and the performance of eddy current testing. The applicant also stated that the flux thimble tubes are cleaned using alcohol and water followed by forced air-drying. After cleaning, a dummy neutron probe is inserted into each flux thimble tube to gauge the flux thimble tube. The flux thimble tubes are then withdrawn to support fuel offload. The applicant further stated that once the fuel is reloaded into the reactor vessel, approximately 16 days later, the flux thimble tubes are reinserted and eddy current testing is performed. The applicant further stated that in order to reduce the potential for condensation buildup, a corrective action is being implemented to perform eddy current testing immediately after cleaning and drying. The applicant also stated that the issue of moisture hindering the ability to collect eddy current data is relatively recent. In addition to the implemented corrective action, the issue is being further investigated, which could result in additional corrective actions focusing on changes to work practices, cleaning and testing procedures, and equipment.

The staff finds the applicant's response to Part 2 of the RAI acceptable because (1) the applicant has determined that the cause of the moisture is from condensation due to changes in containment temperature during the time period between when the flux thimbles are cleaned and dried and when the flux thimbles are eddy current tested and (2) the applicant has implemented corrective actions which will perform eddy current testing immediately after the thimbles are cleaned and dried.

In its response to Part 3 of the RAI, the applicant stated that the Flux Thimble Tube Inspection Program accounts for unexpected wear rates by imposing a lower threshold for corrective action. The applicant stated that the program requires that corrective actions (i.e., replacement, repositioning, or isolation) be taken if a wall loss greater than 60 percent is identified. The applicant also stated that when full-length eddy current test data for each flux thimble tube are not obtained, further review is required to determine additional actions that include replacement, capping, or using a more conservative projection of wear. The more conservative projection is then used against a more conservative criterion of 50 percent wall loss to determine if further actions are required prior to the next scheduled eddy current test.

The staff finds the applicant's response to Part 3 of the RAI acceptable because (1) when full-length eddy current test data for each flux thimble tube are not obtained, further review is performed which requires either replacement, isolation (capping), or a conservative projection of wear and a more conservative wall loss criterion (50 percent wall loss) and (2) the staff's review of the OE database performed during the audit did not reveal any instances of leakage associated with flux thimble tube wear. Therefore, the staff's concerns expressed in RAI B.2.1.24-1 are resolved.

Subsequent to the issuance of the "Safety Evaluation Report with Open Items Related to the License Renewal of Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2," (ADAMS Accession No. ML14296A176) in October of 2014, the staff noted during the NRC 71002 inspection (ADAMS Accession No. ML14311A893) that the applicant had failed to obtain usable eddy current data for the 58 flux thimble tubes at Braidwood Unit 1 during the September 2013 outage. In addition, during the May 2014 flux thimble tubes inspection for Braidwood Unit 2, the applicant was able to obtain eddy current data on only 7 out of 58 flux thimble tubes. Based on the new information, the staff was concerned that the applicant's Flux Thimble Tube Inspection Program might not be adequate if planned inspections were not performed as scheduled.

By letter dated October 10, 2014, the staff issued RAI B.2.1.24-1a, requesting the applicant to:

(1) Describe results of the latest flux thimble tube inspections at Braidwood Units 1 and 2 and provide specific information where tube wear data were not obtained.

(2) Justify the adequacy of the program when tube examinations are not performed as planned.

(3) Provide technical basis to assure that tube wear acceptance criteria are met and that the inspection program is adequate.

(4) Clarify if there have been similar issues at Byron Units 1 and 2, such as not being able to complete eddy current examinations or failure to obtain data on any of the tubes. Describe cases in which higher than expected wear or underpredicting of wear has occurred on any of the tubes.

(5) Clarify if there have been any leakage events at BBS due to flux thimble tube wear.

By letter dated October 31, 2014, the applicant responded to RAI B.2.1.24-1a. In its response to Part 1 of the RAI, the applicant provided a summary of its most recent eddy current testing of flux thimble tubes for Braidwood Station Units 1 and 2. The applicant stated, in part, that full-length eddy current data for all 58 Unit 1 flux thimble tubes were obtained in October of 2010 and showed that 17 of the 58 flux thimble tubes had indications of wear. In addition, the applicant stated that two tubes that were replaced during the prior outage had higher than expected wear. The applicant also stated that, while higher than expected wear during the first cycle of service is not unusual, the station chose to increase the inspection frequency for all flux thimbles from every other cycle to every cycle. However, the applicant stated that during the following cycle (May of 2012), the scope of the eddy current testing was limited to only 16 tubes. The applicant also stated that full-length eddy current data were collected on 15 tubes, while the remaining tube had a flux detector stuck during operation and was replaced. The applicant further stated that the highest amount of wall loss was 49 percent.

The applicant stated that its latest attempt (September 2013) to collect data for Braidwood Unit 1 was aborted after it attempted to collect data on 22 of the 58 flux thimble tubes. The applicant also stated that the eddy current probe was unable to be inserted to the expected area of wear on any of the attempted tubes. The applicant further stated that this was the first time that there was a broad failure to collect flux thimble tube eddy current data for Braidwood Unit 1. The applicant stated that, due to the lack of data, it performed evaluations and capped two flux thimble tubes by using prior wear data along with conservative wear rate projections and acceptance criteria. The applicant also stated that the next scheduled inspection of the flux thimble tubes is scheduled for the spring 2015 outage. (The applicant supplied further information on these outage activities in its letter dated April 13, 2015, as discussed below.)

The applicant stated that, for Braidwood Unit 2, full-length eddy current data on 57 of 58 flux thimble tubes were obtained in May of 2011 and showed that 34 of the 57 flux thimble tubes tested had indications of wear (one tube had a restriction and was removed from service). The applicant also stated that two tubes had higher than expected wear, one tube had been replaced during the previous outage, and the remaining tube was an original equipment flux thimble tube. The applicant further stated that, because of these higher than expected wear rates, the frequency of eddy current testing for all flux thimbles tubes was changed from every other cycle to every cycle. However, the applicant stated that, during the following cycle (November of 2012), the scope of the eddy current testing was “intentionally” limited to only

28 flux thimble tubes due to difficulties encountered during testing. The applicant stated that it was able to get full-length eddy current data on 26 flux thimble tubes, while the remaining two tubes had restrictions. The applicant also stated that two tubes were removed from service (capped) due to high wear. The applicant further stated that the highest amount of wall loss measured for the remaining tubes was 52 percent.

The applicant stated that during its latest attempt (May 2014) to collect data for Braidwood Unit 2, testing was attempted on 39 of 58 flux thimble tubes. The applicant also stated that the eddy current probe was unable to be fully inserted in any of the attempted tubes. The applicant further stated that the eddy current probe was able to get data beyond the area of expected wear on only eight tubes (seven of the eight tubes had indications of wear). The applicant stated that, due to the lack of new data, it performed evaluations by using prior wear data, conservative wear rate projections, and conservative acceptance criteria, and replaced five flux thimble tubes (two tubes which were previously capped were also replaced). The applicant also stated that the next scheduled inspection for the Braidwood Unit 2 flux thimble tubes is scheduled for the fall 2015 outage.

In its response to Part 2 of the RAI, the applicant stated that when full-length eddy current data are not obtained, additional review would be needed to determine further actions, including replacement, capping, or justification for continued service based on a conservative projection of wear obtained from historical data. In describing how projections of wear are made with missing data, the applicant stated that two methods are used: linear projection and a method described in WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear," which is an exponentially decreasing projection. The applicant further stated the higher wear rate projection from the methods is then evaluated, using a more conservative acceptance criterion (i.e., 50 percent wall loss), to determine if any further action is warranted. The applicant also provided an example of how these projections were applied to Braidwood Unit 2 during the May 2014 outage, when inspections were not performed as planned.

In its response to Part 3 of the RAI, the applicant stated that the Flux Thimble Tube Inspection Program assures that acceptance criteria are met by imposing a low threshold for corrective action and an aggressive eddy current test frequency based on unit-specific wear data. The applicant also stated that the program requires that corrective action consisting of replacement, repositioning, or capping be performed when wall loss of greater than 60 percent is identified. The applicant further stated that the program requires that corrective actions be taken when measured wall loss is less than 60 percent but is projected to exceed 80 percent prior to the next scheduled inspection. The applicant stated that corrective actions have been identified to resolve the issues related to performing the eddy current testing for the Braidwood Units 1 and 2 flux thimble tubes.

In its response to Part 4 of the RAI, the applicant stated that Byron Station Units 1 and 2 have the same basic flux thimble design, but Byron Station has not had significant issues in completing eddy current examinations. The applicant stated that Byron Units 1 and 2 and Braidwood Unit 1 use 0.300-in. outside diameter tubes. The applicant also stated that Braidwood Unit 2 uses 0.303-in. outside diameter original tubes and 0.300-in. outside diameter replacement tubes. However, the applicant stated that there is a difference in the vessel internals between the two sites, in that Byron Station internals have antivibration guide sleeves installed during initial construction to reduce flow-induced vibration of the flux thimble tubes. The applicant further stated that, based on review of flux thimble eddy current inspection results since 1999, no tubes have been replaced due to wear at Byron Station. In addition, the applicant stated that, since 1999, there have been only 7 instances, out of a total of

477 attempts, when the eddy current probe could not be inserted to the area of expected wear. As part of its response, the applicant provided a table to summarize its inspections of flux thimble tubes at the Byron Station since 1999 and stated that the ability to obtain eddy current data at the Byron Station has been significantly better than the recent experience at Braidwood Station.

In its response to Part 5 of the RAI, the applicant stated that there have been no events of leakage at either of its stations due to wear of a flux thimble tube.

During the course of the staff's review of the applicant's response to RAI B.2.1.24-1a, by letter dated November 22, 2014, the applicant supplemented its response. The applicant stated that its recent issues with obtaining eddy current data for the Braidwood Station flux thimble tubes have been entered in the corrective action program. Based on these actions, it believes that the data will be obtained in the future. The applicant also stated that the current program accounts for situations when data cannot be obtained by replacing or removing from service flux thimble tubes which cannot be shown by analysis to be satisfactory for continued service. The applicant further stated that, in order to provide additional assurance that the intended function of the flux thimble tubes will be maintained, the program will be enhanced such that, in the event that Braidwood Station has difficulties in obtaining data, those tubes will be conservatively replaced or removed from service. The applicant stated that the enhancement will require the Braidwood Station flux thimble tube(s) to be replaced every three refueling outages or removed from service if eddy current data are not obtained in accordance with the Flux Thimble Tube Inspection Program. As part of its supplemental response, the applicant provided its justification that a three-cycle replacement or removal from service is appropriate, and it revised the License Renewal Commitment List and LRA Sections B.2.1.24 and A.2.1.24 accordingly. As part of the justification, it stated that none of the 116 tubes in both units had to be replaced due to wear after four operating cycles or less.

The staff noted that the applicant's program as revised with the latest enhancements claims consistency with the GALL Report AMP XI.M37, "Flux Thimble Tube Inspection." However, based on the available information, the program is currently not able to perform inspections or obtain usable data from the flux thimble tubes at Braidwood Station. In addition, the staff noted that the applicant had reported that it had experienced high wear rates (i.e., 35 and 37 percent per cycle) and that locations with historically low wear rates had experienced higher wear rates in a subsequent cycle. Therefore, the staff is concerned that, in these instances, degraded tubes would not be identified without successful inspections and that acceptance criteria may not be met for all of the locations. Furthermore, the staff noted that the applicant had reported issues previously with obtaining wear data, or completing scheduled inspections as planned, and had entered these into its corrective action program. It appears that the problems associated with obtaining data were increasing. In addition, the staff noted that, if the moveable detector(s) were stuck, the isolation valves would not be able to isolate the affected thimble tube(s) in the event a leak.

By letter dated January 22, 2015, the staff issued RAI B.2.1.24-1b, requesting that the applicant:

(1) Review the current Flux Thimble Tube Inspection Program for Braidwood, and identify all exceptions to GALL Report AMP XI.M37, "Flux Thimble Tube Inspection." If necessary, provide a plant-specific AMP, which addresses the higher than usual wear rates, and justify the program's long-term viability based on the possibility of not obtaining any inspection data on wear. Describe the technical basis that tube wear acceptance criteria are met and that the program is adequate.

(2) Identify all cases of higher wear (27 percent per cycle or more). Justify the adequacy of the program if tube replacement is performed every three cycles with consideration of the OE of high wear rates as discussed above.

(3) Justify why the historical wear rates would be applicable during the period of extended operation if additional examinations are not performed or did not provide usable data, taking into consideration that wear rates can change.

(4) Provide a root-cause analysis which adequately identifies the problems encountered during the recent inspections; discuss corrective measures to address the problems.

(5) Provide information in regard to instances when detectors became stuck at Braidwood Units 1 and 2. Explain how leakage would be isolated if detectors are stuck when a flux thimble tube develops a leak.

By letter dated February 23, 2015, the applicant responded to RAI B.2.1.24-1b and stated that the intent of the Braidwood Station Flux Thimble Tube Inspection Program is to fully implement the recommendations of GALL Report AMP XI.M37, without exception. The applicant also stated that the recent difficulties in obtaining eddy current testing data have been entered into the Braidwood Station's corrective action program. The applicant further stated, while there is a high confidence that the issues will be resolved in a timely manner, it has enhanced the program to ensure that the integrity of the reactor coolant pressure boundary is maintained until the current issues related to obtaining eddy current data are successfully addressed.

In its response to Part 1 of the RAI, the applicant stated that its intention is to implement the recommendations of the GALL Report AMP XI.M37, without exception. The applicant also stated that exceptions to the GALL Report recommendations as defined in Section 3.0.1 of NUREG-1800 are portions of the recommended GALL Report AMP that the applicant does not intend to implement. As part of its response, the applicant provided a summary of an element-by-element comparison of the Braidwood Flux Thimble Tube Inspection AMP with the recommendation made in the GALL Report AMP XI.M37.

The applicant stated that the historical wear experienced at Braidwood Station, including its "higher than usual wear rates," is bounded by industry OE for which the GALL Report AMP was evaluated. The applicant also stated that the plant-specific conditions, such as materials of construction, service environments, and configuration, are also bounded by conditions for which the GALL Report AMP was evaluated, and therefore, a plant-specific AMP is not necessary.

The applicant stated that, because of its recent problems with getting eddy current data for the flux thimble tubes, the program was enhanced to periodically replace the flux thimbles. However, in the unlikely event that corrective actions do not succeed in getting eddy current data, the applicant will amend its response to IE Bulletin 88-09 and request approval for an alternate inspection technique from the NRC. The applicant further stated that the presumption that inspection data on wear for the Braidwood Station flux thimbles will never be obtained is not reasonable.

The applicant stated that, although it has experienced difficulties in obtaining eddy current testing data, its plant-specific OE confirms that flow-induced wear of flux thimble tubes at Braidwood is in alignment with the wear trends predicted by WCAP-12866. The applicant also stated that the enhancement, which requires replacement of flux thimble tubes every three cycles in the event that eddy current data are not obtained, is conservative based on plant-specific OE. The applicant further stated that, despite the recent problems associated with obtaining eddy current testing data, it is committed to performing periodic eddy current testing, as described in LRA Section A.2.1.24 and the Braidwood Station response to IE Bulletin 88-09, without exceptions.

In its response to Part 2 of the RAI, the applicant stated that, based on its review of eddy current data for Braidwood Station, there were only 18 instances when a flux thimble tube wear equaled to or exceeded 27 percent wear from a single cycle of operation. As part of its response, the applicant provided a table which summarized these instances.

The applicant stated that the adequacy of the enhanced Braidwood Flux Thimble Inspection Program can be justified based on the following: 1) periodic eddy current testing of flux thimble tubes will continue during the period of extended operation, 2) three refueling outage replacement frequency is appropriate since none of the 116 flux thimble tubes were required to be replaced due to age-related degradation in less than four refueling cycles, and 3) industry OE has shown that flux thimble tube wear due to flow-induced vibration decreases exponentially over the service life of a flux thimble tube.

As part of its response to Part 2 of the RAI, the applicant also provided a table which summarized instances when a flux thimble tube was removed from service or replaced in three or fewer cycles. The applicant stated that a total of 17 flux thimble tubes have been replaced in three cycles or less. The applicant stated that four flux thimble tubes were replaced (two after one cycle and two after two cycles) in order to support a modification to the pressurizer water level system. The applicant also stated that three flux thimble tubes were replaced after one cycle due to indications of high wear after the initial cycle of plant operation (the replacements remained in service for at least 15 cycles). The applicant further stated that seven flux thimble tubes were replaced in three cycles or less due to tubes becoming blocked. The applicant stated that two tubes were replaced after one cycle of service because they could not be retracted during the refueling outage. The applicant also stated that one tube was replaced after two cycles of service because of a stuck neutron detector.

In its response to Part 3 of the RAI, the applicant stated that historical flux thimble tube wear rates experienced at Braidwood Station are applicable during the period of extended operation. The applicant also stated that review of flux thimble tube replacements for both units does not indicate that flux thimble tube replacements have increased as the plants have aged. The applicant further stated that plant parameters that may influence flux thimble tube wear include reactor geometry, fuel assembly design, reactor coolant system flow conditions, and flux thimble design. The applicant stated that while changes to fuel have been made, flux thimble tube eddy current test results did not reveal an impact on wear rates. The applicant also stated that significant changes to any of the other parameters have not been made since the start of the issues associated with eddy current testing. Furthermore, the applicant stated that, since approximately 65 percent of the 116 tubes at Braidwood Station are original tubes and have not had any major changes to wear rates, it could be assumed that wear rates are not changing as the plants age.

The applicant stated that, based on its review of historical data, it has determined that a three-cycle replacement frequency is conservative in the unlikely event that useful eddy current data are not collected. The applicant also stated that, although there have been a few instances when flux thimble tubes which had historically low wear rates experienced higher wear rates during a subsequent cycle, these instances have been rare and have not been repeated during multiple test intervals. The applicant further stated that the assumption that the program will have issues with getting usable eddy current data from the present to the end of the period of extended operation is not credible. However, the applicant concluded that a periodic replacement of flux thimble tubes every three cycles, if usable eddy current data are not obtained, will provide assurance that the integrity of the flux thimble tubes is maintained until the current issues have been resolved.

In its response to Part 4 of the RAI, the applicant stated that the potential causes of inspection problems can be summarized as follows: 1) internal obstruction within the flux thimble tubes, such as moisture, lubricant, and debris; 2) deformation of the flux thimble tube(s); or 3) improper eddy current testing equipment/process. The applicant provided its evaluations of each of the causes, which discounted the possibility that internal obstructions or deformation of the tubes could account for the widespread issues experienced with gathering eddy current data for Braidwood Station Units 1 and 2. The applicant stated that it concluded that the most likely cause for its current eddy current issues is related to either flawed eddy current equipment or process. The applicant identified seven corrective actions, which it stated would address all the potential causes of its recent difficulties in obtaining eddy current data at Braidwood Station. The applicant also stated that it planned to complete the corrective actions by spring of 2015, for Unit 1, and fall of 2015, for Unit 2.

In its response to Part 5 of the RAI, the applicant stated that there has been only one occurrence at Braidwood Station Unit 1 (in 2010) when a flux thimble detector became stuck during flux mapping and could not be retracted. The applicant stated that the detector remained in the core until the following outage, when the flux thimble tube and the detector cable were cut and both were replaced. The applicant also stated that, in the event that a flux thimble tube develops a leak, coolant would first fill the tube and flow out from the open end of the tube and into the transfer box located above the seal table. The applicant further stated that the transfer box has a drain line to a sump. As the drain line fills up, it activates an alarm in the main control room, and leakage is contained within the primary containment. The applicant further stated that, in addition to the alarm in the drain line, the seal table rooms are equipped with area radiation monitors. If there is a tube leak, these monitors will detect the increased radioactivity, and an alarm will be activated. The applicant stated that these diverse mechanisms would insure that if a tube leak were to occur, it would be identified quickly.

The applicant stated that the expected leakage from a guillotine break of a single flux thimble tube was determined to be approximately 5 gpm, which is well within the normal makeup capacity of 127 gpm for Braidwood Station units. The applicant also stated that, since individual flux thimble tubes will have different wear rates, failures of multiple flux thimble tubes at the same time are highly unlikely. The applicant further stated that, in the event that a thimble tube develops a leak while a detector is stuck, the resulting leakage would be significantly lower due to the drive cable of the detector restricting the flow. The applicant cited industry experience when a flux thimble tube leak with a stuck detector occurred in 1988 and stated that the resulting leakage was approximately 0.02 gpm.

The applicant stated that Braidwood Station Units 1 and 2 have manual isolation valves that are located above the seal table and can be manually closed when a flux thimble tube develops a leak, if it does not have a stuck detector. The applicant also stated that, in order to isolate a leaking flux thimble tube with a stuck detector, it would be necessary to shut down the reactor and depressurize the reactor coolant system. The applicant further stated that the flux thimble tube and the detector cable would be cut, and the tube would be capped.

Finally, as part of its February 23, 2015, response, the applicant revised the License Renewal Commitment List, LRA Sections B.2.1.24, and A.2.1.24, to provide additional enhancements to perform corrective actions, which would reestablish periodic eddy current testing for Braidwood Station Units 1 and 2.

In its review of the applicant's February 23, 2015, response, the staff noted that the applicant stated that historical flux thimble tube wear experienced at Braidwood is bounded by industry OE for which the GALL Report AMP was evaluated. The staff also noted that the applicant also stated that a plant-specific AMP is not necessary, since its plant-specific condition and age-related OE is bounded by the conditions and OE for which GALL Report AMP XI.M37 was evaluated. The staff further noted that, in its RAI response dated October 31, 2014, the applicant stated that widespread inability to obtain flux thimble tube eddy current data occurred suddenly at Braidwood Station Units 1 and 2 and involved flux thimble tubes of various inservice times. The applicant also stated that while Byron Units 1 and 2 and Braidwood Units 1 and 2 have the same basic flux thimble tube design (i.e., dimensions), the Byron units have not had significant difficulty completing eddy current examinations. In its October 31, 2014, response, the applicant stated that causal factors, which include moisture and lubricant, could account for the difficulties getting eddy current data, and it would consider activities to mitigate this issue.

However, in its response dated February 23, 2015, the applicant stated that moisture and lubricant were not likely the causal factors. In its latest response, the applicant stated that it considered the possibility that deformation of the flux thimble tubes could result in preventing the eddy current probe from being fully inserted. The applicant further stated that deformation could occur because of mishandling, but it is highly unlikely it would result in deformation of all 58 flux thimble tubes. The applicant concluded that the most logical scenario is that the eddy current testing equipment or testing process is the likely cause of the recent issues.

The staff concluded from the applicant's responses that issues with the flux thimble tube inspection program predate the most current inspections, and it appears that failure to obtain data became more widespread. The staff is concerned that the applicant has yet to accurately identify the root cause(s) and, as a result, has not been able to implement corrective actions to effectively resolve the issue(s) with eddy current testing.

In addition, the staff performed an industry OE search and did not identify any similar occurrences of widespread issues with inability to get eddy current data. Furthermore, since the 1980s when flux thimble tube wear became an issue, industry's use of chrome-plated replacement tubes has greatly reduced wear rates, which does not seem to be the case with the replacement flux thimble tubes at Braidwood. The staff is also concerned that the apparent increasing trend of the number of uninspected flux thimble tubes may be due to an age-related deformation of the tubes (i.e., reduction in inside diameter).

In the LRA, the applicant described its program as an existing program, which is consistent with the GALL Report AMP XI.M37, "Flux Thimble Tube Inspection." In its February 23, 2015, response to the staff's followup RAI, the applicant described its program elements as "will be consistent" with the GALL Report AMP XI.M37 program elements. The staff reviewed the applicant's claim of consistency by comparing the applicant's program with the GALL program and noted that several program elements in the applicant's program are not consistent with those of the GALL program. Specifically, the applicant's program failed to obtain useful data from most of its flux thimble tubes during the recent outage inspections since 2012, and the applicant proposed an enhancement to replace the tubes every three cycles if flux thimble tube inspection data could not be obtained. Based on the available information and the applicant's existing OE, the staff concluded there is a possibility that issues with eddy current examinations could recur during the period of extended operation. Therefore, the program would allow replacing the flux thimble tubes at some frequency instead of inspecting them. In such a case, the applicant's program would contain exceptions to the GALL Report AMP's "parameters monitored and inspected," "detection of aging effects," and "monitoring and trending" program elements and, therefore, would not be consistent with the GALL Report AMP.

The staff noted that the applicant stated that its review of historical data from Braidwood Station did not reveal any instances when a flux thimble tube had to be replaced due to age-related degradation in fewer than four (4) cycles. The applicant also stated that industry OE indicates that flux thimble tube wear decreases over the flux thimble tube service life. Based on these and its historical wear rates from the Braidwood Station, the applicant provided an enhancement to the AMP to replace flux thimble tubes every three cycles when inspection data cannot be obtained. However, the staff identified that Table 2, on page 13 of the response, indicates that three tubes had to be replaced after only one cycle of service due to wear, which the staff considers to be age-related. This appears to contradict the applicant's statement that "No flux thimble tube has been replaced due to age-related degradation in less than four (4) cycles."

Additionally, the applicant's justification for the enhancement does not consider more severe wear scenarios. For example, Braidwood had experienced higher than expected wear rates (i.e., 35 percent and 37 percent in one cycle), but the applicant did not consider high wear rates in subsequent cycles. The applicant cited industry OE and stated that wear rates decrease during subsequent cycles following initial high wear rates. The staff noted that a similar plant encountered multiple tube failures prior to the completion of three cycles of operation (i.e., LER-272/1981-028), which contradicts the applicant's assertion that high wear rates will not be repeated during subsequent cycles. In addition, the staff noted that the applicant also reported instances when tubes that had previously experienced little to no wear experienced an increase in wear rates during subsequent cycles.

By letter dated April 2, 2015, the staff issued RAI B.2.1.24-1c, Parts 1, 2, and 3. In Part 1 of the RAI, the staff requested that the applicant:

(a) Provide technical justification that the OE for which the GALL Report AMP was evaluated is applicable to the plant-specific OE at Braidwood, considering the high wear rates and multiple issues with eddy current examinations.

(b) Explain if higher than normal wear rates have been observed with chrome-plated replacement tubes.

(c) Provide root-cause analysis and corrective actions related to the inability to obtain useful inspection data.

(d) Explain if there is a new, age-related mechanism in addition to wear that is causing obstruction of eddy current probe insertion.

(e) If the applicant's OE is unique and not bounded by the OE for which the GALL Report AMP XI.M37 was evaluated, explain why a plant-specific AMP is not required to manage the aging effects during the period of extended operation.

In Part 2 of RAI B.2.1.24-1c, the staff requested that the applicant identify all of the program's exceptions to GALL Report AMP XI.M37, "Flux Thimble Tube Inspection," when flux thimble tube inspection data cannot be obtained. In addition, the staff requested that the applicant (a) discuss how the proposed enhancement will address the exceptions to the GALL Report AMP and (b) revise the LRA AMP as needed, consistent with its response.

In Part 3 of RAI B.2.1.24-1c, the staff requested that the applicant:

(a) Explain why initial wear resulting in replacement of three flux thimble tubes after one cycle is not flow-induced wear and will not recur.

(b) Explain why replacing flux thimble tubes every three cycles when examination data are not obtained is adequate, in light of the plant-specific high wear rates and industry OE which indicates that high wear rates could continue during subsequent cycles and result in tube failures in fewer than three cycles.

By letter dated April 13, 2015, the applicant responded to RAI B.2.1.24-1c and stated that, during the most recent inspection outage for Braidwood Station Unit 1, which started on March 30, 2015, it obtained data on all 58 flux thimble tubes. The applicant also stated that the completion of the recent eddy current testing confirmed that the issue was due to eddy current testing equipment or testing process issues, as stated in its prior response.

The applicant stated that it introduced three improvements to the eddy current test equipment and process as follows:

(1) The flux thimble tubes were not wet cleaned. This eliminated the possibility of residual moisture contributing to increased internal tube friction.

(2) Dry gauging of the flux thimble tubes was performed prior to performing eddy current testing. The gauging process consists of the insertion of a dummy probe to ensure clear passage through the flux thimble tube. A dummy probe is a neutron detector cable without the neutron detector attached. Multiple dry gauging passes, as required, were performed until the technicians felt normal flux thimble tube friction.

(3) Data were collected with a slightly smaller eddy current probe (0.182 in. versus 0.188 in.). The smaller probe provides additional clearance and, therefore, less resistance when inserting the probe in the flux thimble tube.

The applicant stated that the highest measured wear was 68 percent wall loss. This tube was capped during the previous outage and was replaced during this outage. The applicant also stated that, for the balance of the flux thimble tubes, the measured wear ranged from no detectable wear to 46 percent wall loss.

The applicant further stated that the successful eddy current testing on all 58 Braidwood Unit 1 flux thimble tubes provides objective evidence that the past difficulties experienced during flux thimble tube eddy current testing are resolved. The applicant stated that it will perform additional eddy current testing on all flux thimbles during every refueling outage until sufficient data have been accumulated to establish a plant-specific frequency to provide reasonable assurance that predicted wear will not exceed 80 percent before the next scheduled inspection. The applicant also stated that, due to the similarities of Braidwood Unit 1 and Unit 2, it can be concluded that the same actions would also be effective for Unit 2.

In its response to Part 1(a) of the RAI, the applicant stated that the “high wear rates” referenced by the staff’s RAI are bounded by the industry OE for which the GALL Report was evaluated. The applicant stated that GALL Report AMP XI.M37 is based on requirements established as a result of NRC IE Bulletin 88-09, which was developed as a result of industry OE (NRC Information Notice (IN) 87-44). The applicant also stated that, in response to the then emergent OE, the Westinghouse Owner’s Group developed WCAP-12866, which provides a program to manage the wear as well as a model to predict wear rates. The applicant further stated that the WCAP, as well as NRC IN 87-44, both cited high single-cycle wear rates; therefore, the OE for which the GALL Report AMP was evaluated is applicable to the plant-specific experience at Braidwood Station. The applicant concluded by stating that the issues with eddy current examinations were associated with eddy current test equipment and process issues and not related to any known or new age-related degradation.

Based on its review of the applicant's response to Part 1(a) of RAI B.2.1.24-1c, the staff noted that the applicant was able to obtain data on all 58 flux thimble tubes. In addition, based on the data gathered, it did not appear that there had been a dramatic increase in wear rates of the Unit 1 flux thimbles from the last inspection when data were gathered for all 58 flux thimble tubes (2010). Furthermore, the applicant committed (Commitment No. 24) to perform eddy current testing every cycle for Units 1 and 2 until it can establish a plant-specific testing frequency, as well as to replace flux thimble tubes every two cycles if eddy current testing is not performed. The staff noted that the applicant still has not identified the root cause of problems in obtaining data. The applicant applied smaller probes to get data but incurred unfavorable signal-to-noise ratio, which is a challenge to examination reliability and repeatability. Nonetheless, the staff finds the applicant's response acceptable because (a) the applicant was able to perform eddy current testing on all Unit 1 flux thimbles, (b) the wear rates for Unit 1 had not changed significantly, (c) the applicant committed (Commitment No. 24) to performing eddy current testing every cycle for both units until it can establish a plant-specific testing frequency, and (d) the applicant committed to replace flux thimble tubes every two cycles if eddy current data are not obtained in the future. Therefore, the staff's concerns described in Part 1(a) of RAI B.2.1.24-1c are resolved.

In its response to Part 1(b) of the RAI, the applicant stated that a review of flux thimble tube supplier records did not indicate that chrome-plated flux thimble tubes have been provided to Braidwood Station. Therefore, it does not have any plant-specific wear data for chrome-plated flux thimble tubes. The staff finds the applicant's response to Part 1(b) of the RAI acceptable because the applicant confirmed that Braidwood Station has not used chrome-plated flux thimble tubes in an effort to mitigate wear. Therefore, the higher than usual wear rates observed on some of the Braidwood Station flux thimble tubes (35 percent for Unit 1 and 37 percent for Unit 2) cannot be considered unusually high.

In its response to Part 1(c) of the RAI, the applicant stated that the most recent successful eddy current testing performed on all 58 Braidwood Unit 1 flux thimble tubes is evidence that the past difficulties experienced during flux thimble tube eddy current testing were due to eddy current testing equipment or testing procedure issues. The staff does not have sufficient information to determine that the applicant's past failures to get eddy current data were entirely due to issues related to eddy current testing equipment or testing procedure issues. The staff finds the applicant's response acceptable on the merits of the applicant's commitments to (a) establish plant-specific testing frequency by performing eddy current inspections every cycle at Braidwood Station and (b) replace flux thimble tubes every two cycles in the event eddy current data are not gathered at Braidwood Station during the period of extended operation. The staff is confident that, through the implementation of the applicant's Commitment No. 24, the integrity of the flux thimble tubes will be maintained. Furthermore, if there were other issues responsible for the applicant's past issues (i.e., deformation), these would be mitigated through the applicant's successful periodic eddy current testing, or the frequent (two-cycle) replacement of flux thimble tubes in the event that eddy current testing is not performed at Braidwood Station. Therefore, the staff's concerns described in Part 1(c) of RAI B.2.1.24-1c are resolved.

In its response to Part 1(d) of the RAI, the applicant stated that the ability to perform flux mapping along with its ability to insert and retract the flux thimble tubes, coupled with the successful testing of all 58 flux thimble tubes, provides reasonable assurance that the Braidwood Station flux thimble tubes are not deforming, and there is no new age-related degradation which is causing obstruction of flux thimble tubes. The staff noted that the data gathered during the latest eddy current inspection did not show an increase in wear rates for the Unit 1 flux thimbles between the last two cycles since data were last gathered for all 58 flux thimble tubes. The staff also noted there is still a possibility that the Braidwood Station tubes may have become deformed. This opinion is based on the two corrective actions that were cited by the applicant. Specifically, the staff noted that the applicant used a smaller eddy current probe and performed multiple dry gauging with a dummy probe. Furthermore, the Byron Station tubes have the same internal diameter as Braidwood Unit 1's (i.e., 0.301 in.) and did not require similar corrective actions (i.e., smaller probe diameter and gauging with a dummy probe). However, the staff also noted that the applicant has committed (Commitment No. 24) to performing corrective actions which include the commitments to (a) establish plant-specific testing frequency by performing eddy current inspections every cycle at Braidwood Station; (b) implement the same corrective actions for Braidwood Unit 2, which resulted in the successful eddy current testing of all 58 flux thimble tubes; and (c) replace flux thimble tubes every two cycles in the event eddy current data are not gathered at Braidwood Station during the period of extended operation. Therefore, the staff considers the issues in RAI B.2.1.24-1c Part 1(d) resolved, based on the applicant's revised commitments.

In its response to Part 1(e) of the RAI, the applicant restated that the wear rates are not unique to Braidwood Station. The applicant also stated that the widespread issues with obtaining eddy current data are unique to Braidwood Station. However, these are not age-related, but related to eddy current test equipment and procedure issues. The applicant further stated that, since the issues were not age-related and the age-related OE at the station is bounded by industry OE for which the generic AMP was evaluated, a plant-specific AMP is not needed. The staff concluded that the widespread issues with eddy current testing are unique to Braidwood Station. The staff also concluded that the observed wear rates at Braidwood Station are not unique or outside of the wear rates for which the GALL Report AMP was evaluated. As stated previously, the staff does not have sufficient information to make a determination of whether the widespread issues with obtaining eddy current data at Braidwood Station were age-related or related to eddy current equipment and procedure issues. However, the staff considers the issues identified by the staff's RAI B.2.1.24-1c Part 1(e) resolved based on the applicant's revised commitments.

Exception. In its response dated April 13, 2015, to Part 2 of the RAI, the applicant stated that, in order to address the potential of eddy current issues emerging in the future, the following exception will be applied to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements for the Braidwood Flux Thimble Tube Inspection Program:

> Braidwood Flux Thimble Tube Inspection Program operating experience indicates that there have been instances in which useable data could not be obtained for most of its flux thimble tubes during routine flux thimble tube eddy current testing. Although there is confidence that future eddy current testing will be successful, there is a possibility that the issues with the eddy current testing could recur during the period of extended operation. Therefore, there is a possibility that flux thimble tubes will be replaced on a two (2) cycle frequency

rather than the inspections and trending recommended in NUREG-1801, Chapter XI.M37 (Braidwood only).

As part of its response, the applicant provided its justification for the above cited exception and revised LRA Tables 3.1.1 and 3.1.2-1 and Section B.2.1.24 consistent with its response. The applicant stated that the exception is justified based on its enhancements.

In its review of the applicant's response to Part 2 of RAI B.2.1.24-1c, the staff noted that the applicant has identified an exception to the GALL Report AMP, "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The staff finds the cited exception acceptable because the applicant's program enhancements to restore periodic eddy current testing, or to replace or remove from service flux thimble tubes every two cycles, would provide adequate assurance that the integrity of the Braidwood Station flux thimble tubes would be maintained during the period of extended operation. Therefore, the staff's concerns described in Part 2 of RAI B.2.1.24-1c are resolved. The staff's evaluation of the adequacy of the applicant's enhancements is provided in the staff's review of applicant's response to Part 3 of RAI B.2.1.24-1c.

In its response to Part 3(a) of the RAI, the applicant stated that the wear resulting in replacement of three flux thimble tubes (referenced in the applicant's letter dated February 23, 2015) was determined to be event-driven rather than due to aging, because of the relatively short period of time and also because it was not repeated. The applicant stated that the wear was a result of the initial cycle of operation and that the replacement tubes have been in service for at least 15 cycles. The applicant further stated that since the high wear rates at those locations were not repeated during subsequent cycles, it could be assumed that the high wear rates were event-driven and related to the initial cycle.

The applicant stated that factors that may have contributed to the high wear rates for that particular startup cycle could have included the unique flow conditions experienced during the startup testing and initial construction- or manufacturing-related issues, such as burrs, sharp edges, and machine shavings. The applicant also stated that, based on the two-cycle replacement frequency, in the event useful eddy current data are not obtained there is reasonable assurance that the integrity of the flux thimble tubes will be maintained during the period of extended operation.

In its review of the applicant's response to Part 3(a) of RAI B.2.1.24-1c, the staff determined that it is reasonable to exclude unusually high wear rates that can be attributed to the startup of the plant (i.e., first cycle of a plant's operation) if subsequent periodic inspections have confirmed that similar high wear rates have not been reported. The staff finds the applicant's response acceptable; therefore, the staff's concerns described in Part 3(a) of RAI B.2.1.24-1c are resolved.

In its response to Part 3b of the RAI, the applicant stated it had previously provided its justification for the three-cycle replacement frequency (referenced in Exelon letter dated February 23, 2015), which is summarized as follows:

(1) No flux thimble tube has been replaced due to age-related degradation in fewer than four (4) cycles, and there have been only three (3) instances of replacement at four (4) cycles due to age-related wear.

(2) Flux thimble tubes replaced in three (3) cycles or less were replaced due to issues other than flow-induced wear.

(3) Single-cycle wear of 27 percent or greater is rare.

(4) Consecutive cycles with wear of 27 percent or greater do not occur.

(5) Overall wear of the Braidwood flux thimble tubes does not follow a linear trend, rather, it follows the exponentially decreasing trend predicted in WCAP-12866.

The applicant stated that the OE reported in LE-272/1981-028 was considered in the development of WCAP-12866. The applicant also stated that there are significant design differences between the Braidwood Station and the plant which was the subject of LER-272/1981-028, such that Braidwood's historical plant-specific flux thimble wear rates should be considered more relevant than the OE reported by LER-272/1981-028. The applicant further stated that, although its plant-specific operating history supports the three-cycle replacement frequency, in order to account for any additional future uncertainty it will further revise its enhancement.

Enhancement 1. The applicant stated that it will reestablish periodic eddy current testing for each flux thimble tube every refueling outage until sufficient data have been accumulated to establish plant-specific eddy current testing frequency.

Enhancement 2. The applicant's revised enhancements would also require that the Braidwood Station Flux Thimble Tube Inspection Program replace or remove from service a flux thimble tube after two cycles if eddy current data are not obtained.

As part of its April 13, 2015, response, the applicant provided further revisions to LRA Sections A.2.1.24, B.2.1.24, and Commitment No. 24, consistent with this response.

The staff reviewed the applicant's revised enhancements, which will require that flux thimble tubes be replaced every two outages if eddy current data are not obtained. The staff also reviewed the applicant's plant-specific information related to flux thimble tubes, response to RAIs, and historical wear rates at Braidwood Station. The staff noted that Braidwood Station does not use chrome-plated tubes, or design features (i.e., antivibration sleeves) to reduce wear. Therefore, Braidwood Station is reliant entirely on the Flux Thimble Tube Inspection Program to assure that the pressure boundary integrity of all 58 flux thimble tubes is maintained. The staff also noted that the program's failure to obtain data occurred suddenly and could recur during the period of extended operation; therefore, the applicant's revised enhancement to replace or remove from service flux thimble tubes at Braidwood Station every two cycles if eddy current data are not obtained is reasonable in order to account for any future uncertainty.

In its review of the applicant's enhancement, the staff noted that recent data suggested that the Braidwood Station flux thimble tube wear rates can be as high as 35 percent and 37 percent (per cycle). The higher wear rates, which were experienced during initial plant startup (i.e., first cycle of a plant's operation), were confirmed by subsequent periodic inspections to be related to startup activities and do not need to be considered in determining historic plant-specific rates. Therefore, the highest measured wear rates (35 percent and 37 percent) would conservatively justify two cycles of operation during the period of extended operation, in the event the station has a recurring issue with eddy current testing.

In addition, since wear rates will differ from tube to tube, in the unlikely event that there is leakage during the second cycle, under normal operating conditions it will be limited to a single tube. As stated earlier by the applicant, the resulting leakage from a single tube would not challenge the station's nonemergency normal makeup capacity, can be manually isolated by the isolation valves located in the seal table room, and will be limited to the primary containment's sump. The staff also noted that, in the event the leaking tube has a stuck detector, the Station procedures would require a shutdown and depressurization, at which time the tube can be isolated. Again, any potential leakage would be limited to the primary containment's sump. The staff finds the applicant's response acceptable; therefore, the staff's concerns described in Part 3b of RAI B.2.1.24-1c are resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAIs B.2.1.24-1, B.2.1.24-1a, B.2.1.24-1b, and B.2.1.24-1c, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking appropriate corrective actions. In addition, the staff finds that the conditions and OE at the Byron Station are bounded by those for which GALL Report AMP XI.M37 was evaluated. As noted during the above discussion, some aspects of the Braidwood Station OE are unique. As a result, the applicant cited an exception and enhancements to the Braidwood Flux Thimble Tube Inspection Program. In addition, the applicant also identified additional corrective actions, which still need to be completed.

Because these actions are deemed necessary to adequately maintain the pressure boundary integrity for the Braidwood Station flux thimble tubes, the staff will propose incorporating Commitment No. 24 into a license condition in the renewed licenses for Braidwood Station.

UFSAR Supplement. LRA Section A.2.1.24, as revised by letters dated October 31, 2014, November 22, 2014, February 23, 2015, and April 13, 2015 provides the UFSAR supplement for the Flux Thimble Tube Inspection Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff noted that the applicant committed to completing the corrective actions of Commitment No. 25 by the 19th refueling outage which will restore periodic inspection of flux thimble tubes at Braidwood Station. The staff also noted that the applicant also committed to implementing the enhancement after the 19th refueling outage, which will replace or remove from service flux thimble tubes every two refueling outages if eddy current data are not obtained. As stated earlier in this section, the staff will propose a license condition to ensure that these commitments are completed.

The staff finds that the information in the UFSAR supplement, as revised by letters dated October 31, 2014, November 22, 2014, February 23, 2015, and April 13, 2015, is an adequate summary description of the program.

Conclusion.
Byron Station. On the basis of its audit and review of the applicant's Flux Thimble Tube Inspection Program as it applies to Byron, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Braidwood Station. On the basis of its audit and review of the applicant's Flux Thimble Tube Inspection Program as it applies to Braidwood, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification. Also, the staff reviewed the enhancements and confirmed that their implementation will make the AMP, with an exception, adequate to manage the applicable aging effects. In addition, the staff reviewed the applicant's Commitment No. 24 and confirmed that its implementation as specified in the proposed license condition prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.11 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B.2.1.25 describes the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program as consistent with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The LRA states that the AMP will manage loss of material, reduction of heat transfer, and cracking for internal surfaces of metallic piping and components that are exposed to uncontrolled indoor air, diesel exhaust, condensation, raw water, and waste water environments. The LRA also states that the AMP will manage loss of material, hardening, and loss of strength for elastomeric components exposed to condensation, fuel oil, lubricating oil, and treated water environments. As modified for RAI 3.0.3-2 by the applicant's response dated January 13, 2014, this program will also manage loss of coating integrity for a limited number of metallic components with linings or coatings. The LRA further states that the AMP uses visual inspections, and where appropriate, augmented by physical manipulation or pressurization to detect hardening or loss of strength of elastomers.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M38. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M38, as modified in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Tanks, and Corrosion under Insulation," recommends that a representative sample of all material, environment, and aging effect combinations be periodically sampled during each 10-year interval during the period of extended operation. However, during its audit, the staff found that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program did not include assurances that these types of inspections would periodically occur. By letter dated December 13, 2013, the staff issued RAI B.2.1.25-1 requesting that the applicant either revise the program to conduct periodic inspections on a representative sample of in-scope components or provide the bases to show that aging effects for each applicable material and environment combination will be appropriately managed only through opportunistic inspections during periodic surveillances and maintenance activities.

In its response dated January 13, 2014, the applicant revised LRA Sections A.2.1.25 and B.2.1.25 to include the guidance provided in LR-ISG-2012-02 for sample size. The program will now require a representative sample be inspected in each 10-year period during the period of extended operation. The applicant stated that, where practical, the inspections will focus on the bounding or lead components most susceptible to aging based on time in service and severity of operating conditions. The applicant also stated that opportunistic inspections will continue to be performed during each 10-year period despite meeting the minimum sampling requirements. The staff finds the applicant's response acceptable because the revised Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will ensure that appropriate inspections will be performed to identify any aging effects for each applicable material and environment combination during the period of extended operation. The staff's concern described in RAI B.2.1.25-1 is resolved.

As modified for RAI 3.0.3-2 by the applicant's response dated January 13, 2014, this program will also manage loss of coating integrity for a limited number of metallic components with linings or coatings. Based on additional requests by the staff, in its response dated May 5, 2014, the applicant clarified that this program will be used to manage loss of coating integrity for several components that are no longer in service or have been abandoned in place. The staff's evaluation and acceptance of this aspect is documented in SER Section 3.0.3.3.1.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M38.

Operating Experience. LRA Section B.2.1.25 summarizes OE relevant to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. In 2003 and 2005, during scheduled periodic maintenance of a 6-in. check valve for the AFW essential service water booster pump, the applicant identified corrosion and degradation of the valve body and internals due to the raw water environment. After replacing the existing carbon steel valves with the same material, Byron personnel eventually developed and implemented a change to SS material, which has not failed subsequent as-found inspections. The LRA also describes an issue, from 2002, where periodic spiking of containment sump flow rates and corresponding level changes were found to be caused by foreign material in the reactor containment fan cooler drip trays. The applicant initiated preventive maintenance work orders to periodically inspect and clean all drip trays in both units.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M38 was evaluated.

UFSAR Supplement. LRA Section A.2.1.25, as modified in the applicant's response dated January 13, 2014, 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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that, as described in Commitment

No. 25, the applicant will implement the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff also concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.12 Lubricating Oil Analysis

Summary of Technical Information in the Application. LRA Section B.2.1.26 describes the existing Lubricating Oil Analysis program as consistent with GALL Report AMP XI.M39, "Lubricating Oil Analysis." The program is a preventive and mitigative program that directs scheduled activities that include routine sampling, analyses, and trending, thereby, preserving an oil environment in piping, piping components, piping elements, valve bodies, pump casings, gear boxes, tanks, and heat exchangers that is not conducive to loss of material or reduction of heat transfer. The LRA also states that selected components will be inspected as described in the One-Time Inspection (B.2.1.20) program, to ensure that age-related degradation does not occur and thereby ensuring the effectiveness of the Lubricating Oil Analysis program. As amended by letters dated January 13, 2014, and June 30, 2014, the applicant enhanced the program to include managing loss of coating integrity for internally coated components.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M39. Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M39. The staff's evaluation of the changes to the Lubricating Oil Analysis program to address loss of coating integrity is documented in SER Section 3.0.3.3.1.

Operating Experience. LRA Section B.2.1.26 summarizes OE related to the Lubricating Oil Analysis program.

Byron Station. In March 2012, a routine oil sample was taken from the 0A essential service water makeup pump diesel crankcase. The oil sample analysis results showed an elevated silicon level at 21 ppm. The "alert" level is 20 to 30 ppm. An alert level indicates that there is an adverse trend or deviation from normal operating conditions, but there is a low probability of damage or failure of the equipment. Silicon levels are an indication of the amount of dirt, grit, anti-foam agents, seals, grease, gasket sealants, or other coolant additives present in the oil. This condition was entered into the CAP. All the other oil parameters were at normal and acceptable levels. The lab retested the oil sample and confirmed the test results. An analysis of the historical oil sample results and trends of both 0A and 0B essential service water makeup pump diesels showed that the silicon levels in the crankcase oil increases linearly about 2 to 5 ppm per quarter with normal diesel engine service. The condition of the crankcase oil was evaluated to be acceptable for continued use until the scheduled oil change in June 2012. The

0A essential service water makeup pump diesel crankcase oil was changed with new oil that met all required specifications in June 2012. The old oil was analyzed and the results were similar to the March 2012 oil analysis results with elevated silicon levels and all other parameters at normal acceptable levels.

In April 2011, a routine oil sample was taken from the 1A containment chiller oil sump. The oil sample analysis results showed a decrease in oil viscosity to 47.9 cSt at 40 °C (100 °F). The normal range for this oil type is 61.2 to 74.8 cSt at 40 °C. This condition was entered into the CAP for evaluation and trending. An analysis of the historical oil sample results and trends of the other three (1B, 2A, and 2B) containment chiller oil sample results showed that a decrease in viscosity is expected during the service life of the oil. The oil viscosity decreases because Freon gets entrained in the lubricating oil during normal chiller operation. All the other oil parameters were at normal acceptable levels. The condition of the chiller oil was evaluated to be acceptable for continued use until the scheduled oil change in January 2012. The 1A containment chiller oil was changed out with new oil that met all required specifications in January 2012. The old oil was sampled and analyzed and the results showed that the old oil quality was still acceptable for continued use in the chiller.

Braidwood Station. A FASA was performed for the Braidwood lubrication sampling program in 2005. The FASA identified deficiencies in the administration of the trending software program in accordance with corporate procedures and standards. Specifically, there were inconsistencies between the oil sample parameter alarm limits in the lubricating oil trending software and the Exelon Oil Analysis Interpretation Guideline. This inconsistency was causing many components to be in a “red” status when no adverse condition existed. A “red” status means that action is required to resolve the abnormal oil parameter condition. This issue was entered into the CAP. The Braidwood lubrication oil program coordinator resolved the discrepancies by aligning the oil sample parameter data set alarm limits in the trending software program to those that were explicitly defined in the oil analysis interpretation guideline. As a result, many components that were incorrectly marked as being in a “red” status were adjusted to a “green” status. A “green” status means that the oil parameter is in the normal acceptance band. This improvement to the trending software program eliminated many “false” alarms regarding the monitoring of component lubricating oil trends at Braidwood.

In May 2005, a routine oil sample analysis of the 2B centrifugal charging pump gearbox oil showed a copper level of 35 ppm, which was greater than the acceptance criteria of 30 ppm. A review of previous oil sample results revealed that the copper content in the 2B centrifugal charging pump gearbox oil had jumped up from 3 ppm to 35 ppm over the prior 6 months. All the other oil parameters were within the normal acceptance limits. This issue was entered into the CAP. The centrifugal charging pump was still operable because the other oil parameters were all within their acceptance limits, the pump vibration analysis was normal, and the pump thermography analysis was normal. The copper content in the other centrifugal charging pumps (1A, 1B, and 2A) were within specifications; therefore, the extent of condition was limited to the 2B centrifugal charging pump. An adverse condition monitoring plan was implemented to more closely monitor the performance of the 2B centrifugal charging pump until the maintenance work could be performed on the gearbox. The gearbox oil temperature and oil pressure was monitored frequently while the pump was operating. Vibration signatures and thermography images were taken more frequently. The initial determination of the possible source of the copper in the 2B centrifugal pump gearbox oil used industry OE, lubricating oil analysis guidelines, and collaboration with other subject matter experts. For example, the oil analysis interpretation guideline explained that possible sources of the copper include wear from journals, rolling element bearing retainers, oil cooling coils, oil additive, bushings, thrust bearings and washers, or slinger rings. It was determined that the most likely source of the copper is from wear of the bronze components in the gearbox. The 2B centrifugal charging pump gearbox was inspected in July 2006. The source of copper was identified as coming from a high speed bearing that was found with its babbitt worn away. The high speed bearing was replaced. All the other bearings were inspected and found to be in good condition. The cause of the missing babbitt on the high speed bearing was most likely due to excessive long term wear of the shaft on the bearing. The remaining 2B centrifugal charging pump work was completed with no other discrepancies. The subsequent 2B centrifugal charging pump gearbox oil samples have shown the copper levels to be normal levels at less than 30 ppm.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program. Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M39 was evaluated.

<u>UFSAR Supplement</u>. As amended by letters dated January 13, 2014, and June 30, 2014, LRA Section A.2.1.26 provides the UFSAR supplement for the Lubricating Oil Analysis program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to ongoing implementation of the existing Lubricating Oil Analysis program for managing the effects of aging for applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's Lubricating Oil Analysis program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.13 Monitoring of Neutron-Absorbing Materials Other than Boraflex

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.27 describes the existing Monitoring of Neutron-Absorbing Materials Other than Boraflex Program as consistent with GALL Report AMP XI.M40, "Monitoring of Neutron-Absorbing Materials Other than Boraflex." The Monitoring of Neutron-Absorbing Materials Other than Boraflex AMP periodically inspects and analyzes test coupons of the Boral material in the spent fuel storage racks to determine if the neutron-absorbing capability of the material has degraded over time. This program ensures that a 5 percent subcriticality margin in the spent fuel pool (SFP) is maintained

during the period of extended operation by monitoring for loss of material, changes in dimension, and loss of neutron-absorption capacity of the Boral material.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M40. Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M40.

The staff also reviewed the portions of the "monitoring and trending" program element associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. LRA Section B.2.1.27 includes an enhancement to the "monitoring and trending" program element. The applicant stated that prior to the period of extended operation, an enhancement will be implemented to maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks, by ensuring that the coupons have been surrounded with a greater number of freshly discharged fuel assemblies than that of any other cell location. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M40 and finds it acceptable because when it is implemented it will ensure that the Boral coupons will lead the Boral racks in total exposure through the period of extended operation.

Operating Experience. LRA Section B.2.1.27 summarizes OE related to the Monitoring of Neutron-Absorbing Materials Other than Boraflex Program.

Byron Station. In 2007, the results of neutron-attenuation testing of a Boral coupon indicated a 5.28 percent decrease in boron-10 concentration; therefore, exceeding the acceptance criteria of 5 percent. This condition was entered into the CAP for evaluation. As part of the corrective actions taken, the results of the coupon surveillance, as well as other previous coupon inspection data from both BBS, were sent to the spent fuel rack manufacturer for evaluation. Based upon the manufacturers' review of data, it was concluded that the nonconforming coupon results were likely attributed to measurement uncertainty and differences in measurement equipment and techniques between the pre-irradiated and post-irradiated coupon data. In order to eliminate uncertainties between pre-irradiated data and post-irradiated data, and to establish a more accurate trend in the boron-10 content of the failed coupon, the manufacturer recommended to return the Boral test coupon to the SFP for subsequent testing. The Boral coupon was returned to the SFP, and subsequent testing is planned. Furthermore, another coupon was tested in 2010, and all acceptance criteria were met satisfactorily. As a result, Boral coupons will continue to be inspected in accordance with the manufacturers' recommended frequency. Based upon the results of the three coupons inspected prior to 2007, as well as the fifth coupon inspected in 2010, the recommended frequency is sufficient to detect degradations of the Boral neutron-absorber material prior to a loss of intended function.

Braidwood Station. In April 2003, it was identified that Braidwood Station was not performing accelerated irradiation of the Boral coupon tree in accordance with the manufacturers' recommendations. The manufacturers' recommendations included surrounding the coupon tree with freshly discharged fuel assemblies on all eight sides following the first five refueling cycles, of a single unit, after installation of the racks. The new high density Boral SFP racks were installed in the common Braidwood SFP in the spring of 2001. Following the Unit 1 fall 2001 refueling outage, freshly discharged fuel assemblies were placed on all eight sides of the coupon tree. Approximately 3 months later in January 2002, three fuel assemblies surrounding the coupon tree were removed and not replaced. In April 2003, this condition was discovered and entered into the CAP. As a result, the coupon tree was relocated to a location where it was surrounded on all eight sides by fuel recently discharged from Unit 2 following its last refueling outage in early 2002. Approximately 1 month later, at the conclusion of the Unit 1 refueling outage in May 2003, the coupon tree was again relocated and surrounded on all eight sides by recently discharged Unit 1 fuel assemblies to resume the accelerated irradiation plan as originally directed by the manufacturer. Work orders were created to ensure compliance with the manufacturers' recommendations to maintain the coupon tree surrounded by recently discharged fuel assemblies through at least the fifth refueling cycle following installation of the spent fuel racks.

The staff reviewed OE information in the application, and during the audit, to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

- Both Byron and Braidwood have OE where the coupon tree holding the Boral sample coupons was not surrounded by freshly discharged fuel in accordance with the original equipment manufacturer's recommendations. In order to have an effective coupon monitoring program, the coupons should be the leading indicators of material degradation as compared to the neutron absorber material in the spent fuel storage racks. That is, the dose received and/or long-term exposure to the wet pool environment by the coupons should be bounding of the material in the racks. Allowing the coupons to lead the neutron absorber material in the racks provides reasonable assurance that the applicant will detect any material degradation in the coupons before the material in the SFP racks starts to degrade.
- By letter dated February 7, 2014, the staff issued an RAI B.2.1.27-1, requesting that the applicant discuss how the coupon exposure (i.e., coupon tree location) will provide reasonable assurance that Boral degradation is identified prior to potential loss of neutron-absorbing capability of the material in the spent fuel racks. If the coupon exposure to the environment is not bounding of the material in the racks, the staff requested the applicant discuss how the aging effects of the Boral material will be managed for the unbounded racks.
- By letter dated March 4, 2014, the applicant responded by stating that procedural control of the location and the loading of freshly discharged fuel around the Boral coupon tree will provide reasonable assurance that Boral degradation will be identified prior to potential loss of neutron-absorbing capability of the Boral material in the SFP racks. The applicant further stated that an enhancement would be made to the program, requiring that coupon exposure be maintained such that it is bounding for the Boral material in all of the SFP racks, prior to the coupons being examined, by ensuring that the coupons have been surrounded with a greater number of freshly discharged fuel assemblies than any other cell location in the pool. Thus, the Boral coupon tree will receive a higher dose than any other cell location and will be bounding of the Boral material in the racks.
- The staff finds the applicant's response acceptable because the applicant's program enhancement, along with the accelerated irradiation schedule of the Boral coupon tree already performed by the applicant, will ensure that the coupons remain leading the

Boral racks in total exposure. The staff's concerns with RAI B.2.1.27-1 have been resolved.

Based on its audit and its review of the application, and review of the applicant's response to RAI B.2.1.27-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M40 was evaluated.

UFSAR Supplement. LRA Section A.2.1.27 provides the UFSAR supplement for the Monitoring of Neutron-Absorbing Materials Other than Boraflex Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Neutron-Absorbing Materials Other than Boraflex Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Title 10 of the 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 10 CFR Part 50, Appendix J

Summary of Technical Information in the Application. LRA Section B.2.1.32 describes the existing 10 CFR Part 50, Appendix J Program as consistent with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J." The LRA states that the AMP monitors leakage rates through the containment pressure boundary, including the containment liner, associated welds, penetrations, fittings, and other access openings. The LRA also states that the AMP provides for aging management of pressure boundary degradation for electrical penetration assemblies, mechanical penetrations, penetration bellows and sleeves, the containment liner, bolting, personnel airlock, equipment hatch and seals, gaskets, and moisture barriers due to loss of material, loss of dealing, loss of leaktightness, loss of preload, or cracking in systems penetration containment in air-outdoor, air with borated water leakage, condensation, and wastewater environments. The LRA further states that consistent with the CLB, the containment leak rate tests are performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, Option B; Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," NEI 94-01 "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S4. Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S4.

Operating Experience. LRA Section B.2.1.32 summarizes OE related to the 10 CFR Part 50, Appendix J. A summary of the OE is given below.

- A FASA for the Byron 10 CFR Part 50, Appendix J Program was conducted in May 2010 to evaluate compliance of the program with regulatory and procedural requirements. No issues were identified that affected the operability of the plant or that had regulatory impact; however, three standards deficiencies and 20 recommendations were identified. Activities were assigned to track resolution of the deficiencies and implementation of the recommendation.
- In April 2005, a local leakage rate test (LLRT) for the Byron Unit 2 emergency personnel airlock door exceeded the acceptance criteria. Maintenance personnel performed the corrective action to adjust the door latch. The subsequent LLRT was repeated with acceptable results.
- A FASA for the Braidwood 10 CFR Part 50, Appendix J Program was conducted in 2012 to evaluate compliance of the program with regulatory requirements and Exelon procedure ER-AA-380. No issues were identified that affected the operability of plant equipment or that had regulatory impact; the assessment identified seven recommendations and one strength. Activities were assigned to track implementation of the recommendations.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S4 was evaluated.

UFSAR Supplement. LRA Section A.2.1.32 provides the UFSAR supplement for the 10 CFR Part 50, Appendix J Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to ongoing implementation of the existing 10 CFR Part 50, Appendix J Program for managing the effects of aging for applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's 10 CFR Part 50, Appendix J Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.37 describes the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements as consistent with GALL Report AMP XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The LRA states that the AMP addresses insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture through the period of extended operation. The LRA also states that the AMP proposes to visually inspect cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.E1 to determine whether the program will be adequate to manage the aging effects for which it is credited.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E1.

Operating Experience. LRA Section B.2.1.37 summarizes OE related to the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.E1 was evaluated.

UFSAR Supplement. LRA Section A.2.1.37 provides the UFSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the new Insulation Material for 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 finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Summary of Technical Information in the Application. LRA Section B.2.1.38 describes the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits as consistent with GALL Report AMP XI.E2, "Insulation Material for Electrical Cables and Connections Not subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The applicant stated that the program will be used to manage aging of cable and connection insulation of in-scope portions of the radiation monitoring system (Byron and Braidwood) and portions of the reactor protection system (Braidwood neutron monitoring only). The applicant identified the in-scope process instrumentation circuits as sensitive instrumentation circuits with high-voltage, low level current signals located in areas where cables and connections could be exposed to adverse localized environments caused by temperature, radiation, or moisture.

The applicant further stated that by reviewing normal calibration or surveillance results, severe aging degradation may be detected prior to the loss of cable and connection intended function. As stated by the LRA, the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements will be implemented prior to the period of extended operation. A proven cable test will be performed for the in-scope neutron monitoring circuits. The LRA also states these calibration and cable tests will be performed prior to the period of extended operation. The LRA further states that the first review of the results will be assessed for reduced insulation resistance prior to the period of extended operation and at least once every 10 years 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 compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.E2.

For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI as discussed below.

The applicant stated that LRA AMP B.2.1.38, "Insulation Material For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," is a new program that is consistent with GALL Report AMP XI.E2, "Insulation Material For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits."

The “scope of program” program element in GALL Report AMP XI.E2 recommends that this AMP applies to electrical cables and connections (cable system) used in circuits with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation that are subject to an AMR and subject to adverse localized environments caused by temperature, radiation, or moisture.

However, during its audit, the staff found that the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits Program did not identify power range neutron monitoring circuits as within the scope of this AMP. By letter dated January 13, 2014, the staff issued RAI B.2.1.38-1 requesting the applicant to explain why power range neutron monitoring circuits were not within the scope of LRA AMP B.2.1.39 for both BBS.

In its response dated February 4, 2014, the applicant stated:

> The power range neutron monitors at Byron and Braidwood are included in the scope of the Byron and Braidwood Environmental Qualification (EQ) program. The power range neutron monitoring circuits are not in the scope of LRA AMP B.2.1.38 ‘Insulation Material for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,’ for both Byron and Braidwood because they are managed by the LRA AMP B.3.1.3, ‘Environmental Qualification (EQ) of Electric Components.’
>
> For completeness, a description of the portions of the Radiation Monitoring System and the Reactor Protection System in the scope of LRA AMP B.2.1.38 ‘Insulation Material for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,’ for Byron and Braidwood is provided below:
>
> a. Portions of the Radiation Monitoring System:
>
> 1. Fuel handling incident area radiation monitors
> 2. Control Area Ventilation System control room outside air intake and control room turbine building air intake radiation monitors
> 3. Main steam line and piping penetration area radiation monitors
> 4. Auxiliary Building vent stack wide range gas monitor
>
> b. Portions of the Reactor Protection System:
>
> 1. Source range / intermediate range neutron monitors (SR/IR) (Braidwood only)

The applicant stated that the source range and intermediate range neutron monitors at Byron are included in the scope of the EQ program.

The applicant clarified the applicable in-scope radiation monitoring instrumentation for LRA AMP B.2.1.38. The applicant also clarified the scoping and aging management for the source range and intermediate range neutron monitors and the power range neutron monitoring instrumentation circuits. The applicant revised LRA Sections A.2.1.38 and B.2.1.38 consistent with the applicant's RAI response. The staff finds the applicant's response acceptable because the applicant provided clarification that the power range neutron monitoring instrumentation is within the scope of license renewal with aging management performed under LRA AMP B.3.1.3, "Environmental Qualification (EQ) of Electric Components," (Byron and Braidwood). The applicant also clarified the applicable AMPs for the source range and intermediate range neutron monitoring instrumentation with Byron included within the scope of LRA AMP B.3.1.3, "Environmental Qualification (EQ) of Electric Components," and Braidwood age managed by LRA AMP, B.2.1.38, "Insulation Material for Electrical Cables and Connections Not subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The applicant revised LRA Sections A.2.1.38 and B.2.1.38 to clarify the applicable AMPs for in-scope instrumentation including power range neutron monitors (Byron and Braidwood) and source range and intermediate range neutron monitors (Braidwood only). The staff's concern described in RAI B.2.1.38-1 is resolved.

For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI as discussed below.

The GALL Report AMP recommends that cable testing be conducted when the calibration or surveillance program does not include the cabling system in the testing circuit. A proven cable system test for detecting deterioration of the insulation system (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation as justified in the application) should be performed.

However, during its audit, the staff found that LRA AMP B.2.1.38 program element "detection of aging effects" states that cable system testing will be credited as an alternative approach to the review of surveillance or calibration results and will be performed using a proven, industry accepted, cable system test for detecting deterioration of the insulation system. The staff was concerned that the applicant's AMP could allow the review of calibration results even though the cable system is not included in the calibration or surveillance program. The applicant's AMP states that a proven, industry accepted, cable system test for detecting deterioration for the cable system insulation will be performed. However, the applicant does not identify the type of test that can be used. In the absence of these testing techniques, the staff could not determine the consistency of the "detection of aging effects" program element to GALL Report AMP XI.E2.

By letter dated January 13, 2014, the staff issued RAI B.2.1.38-2 and B.2.1.38-3 requesting the applicant to clarify cable system test requirements applicability and identify the test techniques to be used for the detection of the deterioration of electrical cable and connection insulation systems under LRA AMP B.2.1.38, for both BBS.

In its response dated February 4, 2014, the applicant stated:

> Calibration testing will be performed for the in-scope circuits when the cables are included as part of the calibration circuit. A proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation) will be performed for the in-scope circuits, including in-scope nuclear instrumentation circuits, when the

cables are not included as part of the calibration circuit. These calibration and cable tests will be performed prior to the period of extended operation.

The applicant revised LRA Sections A.2.1.38 and B.2.1.38 as well as Commitment No. 36 to reflect these cable testing techniques.

The staff finds the applicant's response acceptable because the applicant provided clarification that calibration testing would be performed when the cable is part of the calibration and identified the applicable test methods to be used when in-scope cables are not part of the of the calibration circuitry. The staff also finds that the applicant's revised LRA UFSAR Summary A.2.1.38, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"; LRA AMP B.2.1.38, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"; and LRA Table A5, "Commitment List," Commitment No. 38, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits" to be consistent with SRP-LR Table 3.0-1 and GALL Report AMP XI.E2, "Insulation Material for Electrical Cables and Connections Not subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," program element "detection of aging effects." The staff's concerns described in RAI B.2.1.38-2 and B.2.1.38-3 are resolved.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.38-1, B.2.1.38-2, and B.2.1.38-3, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E2.

Operating Experience. LRA Section B.2.1.38 summarizes OE related to the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits Program.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.E2 was evaluated.

UFSAR Supplement. LRA Section A.2.1.38 provides the UFSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1 and noticed that the applicant did not identify the type of tests (e.g., such as insulation resistance tests, time domain reflectivity tests, or other tats judged to be effective as justified in the application). The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement.

By letter dated January 13, 2014, the staff issued RAI B.2.1.38-3 requesting that the applicant provide the testing techniques to be used for detecting deterioration of the instrumentation circuit insulation system.

In its response dated February 4, 2014, the applicant stated that testing techniques for detecting deterioration of the instrumentation circuit insulation system are proven cable tests such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition. The applicant revised LRA Sections A.2.1.38, B.2.1.38, and LRA Table A.5, "Commitment List," Commitment No. 38.

The staff finds the applicant's response acceptable because the applicant has identified the applicable test techniques and revised LRA Sections A.2.1.38 and B.2.1.38 consistent with GALL Report AMP XI.E2 and SRP-LR Table 3.0-1. Therefore, the UFSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits is consistent with the program description in the GALL Report and the UFSAR summary report in the SRP-LR. The staff's concern described in RAI B.2.1.39-3 is resolved.

The staff also noticed that the applicant committed to implement the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits Program prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended by letter dated February 4, 2014, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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).

3.0.3.1.17 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.39 describes the new Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program as consistent with GALL Report AMP XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages non-EQ, in-scope, inaccessible or underground (e.g., in conduit, duct bank, or direct buried) power cable aging effects and mechanisms including exposure to significant moisture. The applicant also stated that for this program, power is defined as greater than or equal to 400 V and significant moisture is defined as

periodic exposure to moisture that lasts more than a few days (e.g., cable wetting or submergence in water). The applicant further stated that power cable exposure to significant moisture may cause reduced insulation resistance that can potentially lead to failure of the cable's insulation system.

The applicant stated that in-scope cables for this AMP will be tested using a proven test for detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence. The applicant also stated that corrective actions such as more frequent testing or replacement of the affected cable are taken and a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible in-scope power cables when test results do not meet acceptance criteria or OE suggest more frequent testing is necessary. The applicant committed to test in-scope inaccessible power cables at least once every 6 years with the first tests completed prior to the period of extended operation.

The applicant stated that periodic actions will be taken to prevent inaccessible cable from being exposed to significant moisture. The applicant also stated that manholes associated with the cables included in the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be inspected to assure cables are not wetted or submerged, cable and connections are intact without observable surface damage, cable support structures are intact, and drainage systems or dewatering devices and associated alarms, if installed, are operating properly. The applicant further stated that the frequency of inspections for accumulated water will be established and adjusted based on plant-specific OE with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. In addition, the applicant stated that operation of dewatering devices, if installed, will be verified prior to any known or predicted heavy rain or flooding event. The applicant specified that the inspections will occur at least annually with the first inspection completed prior to the period of extended operation.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.E3.

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

The applicant stated that LRA AMP B.2.1.39, "Inaccessible Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," is a new program that is consistent with the GALL Report AMP XI.E3, "Inaccessible Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements." The GALL Report AMP XI.E3 program element "preventive actions" states that if water is found during inspections (i.e., cable exposed to significant moisture) corrective actions are taken to keep the cable dry and assess cable degradation. However, the "preventive actions" program element of LRA AMP B.2.1.39 (Basis Document BBS-PBD-AMP-XI.E3) only states if water is found during inspection, water is drained and other corrective actions are taken, as appropriate.

The staff was concerned that the applicant's program may not be consistent with the GALL Report AMP XI.E3 in that it does not specifically include an assessment of cable degradation (e.g., tests to assess cable condition) when inaccessible power cables are exposed to significant moisture. By letter dated January 22, 2014, that staff issued RAI B.2.1.39-1 requesting the applicant to identify testing and inspection techniques used to assess the condition of inaccessible cables when cables are exposed to significant moisture.

In its response dated February 19, 2014, the applicant stated the LRA AMP B.2.1.39, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," will include an assessment of cable degradation when inaccessible power cables are exposed to significant moisture. The assessment of cable degradation includes direct visual inspection inside the cable vault and an evaluation of cable test results. The applicant stated that the "preventive actions" program element of AMP Basis Document BBS-PBD-AMP-XI.E3 for LRA B.2.1.39, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," is revised to clarify the "preventive actions" program element is consistent with the GALL Report. The applicant revised the "preventive actions" program element as shown below:

> This condition monitoring aging management program takes periodic actions to prevent cables from being exposed to significant moisture. This program inspects manholes and associated accessible conduit ends for the non-EQ, in-scope, inaccessible cables (greater than or equal to 400 volts), for water collection so that draining or other corrective actions can be taken.
>
> The objective of the inspections, as a preventive action, is to prevent inaccessible cables from being exposed to significant moisture. Therefore, the inspection frequency for water collection is established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The inspections occur at least annually. The inspection includes direct observation to assure cables are not wetted or submerged, cables and connections are intact without observable surface damage, cable support structures are intact, and drainage systems or dewatering devices, if installed, and associated alarms are operating properly. Manhole dewatering devices, if installed, are either (1) equipped with alarms signifying less than adequate functioning of dewatering devices, or (2) inspected as part of procedural controlled activities for a potential significant weather event. If water is found during inspection, corrective actions are taken to keep the cable dry and to assess cable degradation. The first inspections for license renewal will be completed prior to period of extended operation.

The staff finds the applicant's response acceptable because Basis Document BBS-PBD-AMP-XI.E3, "Preventive Actions," program element has been revised by the applicant to include preventive actions consistent with the GALL Report AMP XI.E3, "Preventive Actions" program element. The staff's concern described in RAI B.2.1.39-1 is resolved.

The "detection of aging effects" program element of LRA AMP B.2.1.39 states that the condition of cable insulation is assessed with reasonable confidence using one of the following techniques: Dielectric Loss (Dissipation Factor or Power Factor), Alternating Current (AC) Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state of the art at the time the tests are performed. However, the GALL Report AMP XI.E3 states that the applicant can assess the condition of the cable insulation with reasonable confidence using one or more tests.

Limiting the number of tests performed to one test may result in inadequate detection of cable insulation degradation. For example, EPRI has stated that three practical tests are currently available for shielded extruded polymer medium-voltage cable: partial discharge, tan δ, and power frequency or very low frequency withstand. Depending on the nature of the cable design and the cable or accessory (termination or splice), more than one test may be needed to assess cable insulation degradation. The staff was concerned that the applicant's program may not be consistent with the GALL Report AMP XI.E3 in that it may limit the "detection of aging effects" program element to a single test to detect cable insulation degradation. By letter dated January 22, 2014, that staff issued RAI B.2.1.39-2 requesting the applicant to explain why limiting LRA AMP B.2.1.39 to a single test to detect cable insulation degradation is consistent with GALL Report AMP XI.E3.

In its response dated February 19, 2014, the applicant stated that the LRA AMP B.2.1.39, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," assesses the condition of the cable insulation with reasonable confidence using one or more tests. LRA Section A.2.1.39 states, in part, "One or more tests may be used to determine the condition of the cables so they will continue to meet their intended function during the period of extended operation." Limiting LRA AMP B.2.1.39 to a single test to detect cable insulation degradation is not consistent with GALL Report AMP XI.E3.

The applicant stated that the "detection of aging effects" program element of AMP B.2.1.39, "Inaccessible Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," and LRA Section B.2.1.39, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," are revised to clarify the "detection of aging effects" program element is consistent with GALL Report AMP B.2.1.39. The applicant revised the "detection of aging effects" program element as shown below:

> The BBS non-EQ, in-scope, inaccessible power cables, which are exposed to significant moisture, are tested at a frequency of at least every 6 years. The first tests will be performed prior to period of extended operation. The 6-year interval provides multiple data points which can be used to characterize the rate of degradation, if occurring. This is an adequate period to monitor performance of the cables and take appropriate corrective actions since experience has shown that aging degradation is a slow process. More frequent testing may occur based on test results and operating experience. The first tests for license renewal are to be completed prior to period of extended operation.
>
> The condition of cable insulation is assessed with reasonable confidence using one or more of the following techniques: Dielectric Loss (Dissipation Factor or Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the tests are performed. Tests assure that cables will continue to perform their intended functions during the period of extended operation.

The staff finds the applicant's response acceptable because Basis Document BBS-PBD-AMP-XI.E3, "Detection of Aging Effects," program element has been revised by the applicant to specify one or more tests for the condition assessment of cable insulation. The staff finds that the applicant's "detection of aging effects" program element is now consistent with the GALL Report AMP XI.E3, “Detection of Aging Effects” program element. The staff’s concern described in RAI B.2.1.39-2 is resolved.

The “monitoring and trending” program element of LRA AMP B.2.1.39 (Basis Document BBS-PBD-AMP-XI.E3, “Monitoring and Trending”) states that test results that have the ability to trend are trended to provide additional information on the rate of cable degradation. GALL Report AMP XI.E3 states that trending actions are included as part of this AMP, although the ability to trend results is dependent on the specific type of tests or inspections chosen. Trended results provide additional information on the rate of cable insulation degradation. By letter dated January 22, 2014, that staff issued RAI B.2.1.39-3 requesting the applicant to explain why not including trending of inspection results is consistent with GALL Report AMP XI.E3.

In its response dated February 19, 2014, the applicant stated that consistent with current operating term practice, LRA AMP B.2.1.39 will include trending the inspection results in addition to trending the testing results. The applicant also stated:

> The ‘monitoring and trending’ program element of the AMP Basis Document for LRA AMP B.2.1.39, ‘Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements’ is revised to clarify that the ‘monitoring and trending’ program element includes trending of the inspection results that are trendable. The ‘monitoring and trending’ program element of the AMP Basis Document now states: Test or inspection results that are trendable are trended to provide additional information on the rate of cable degradation.

The staff finds the applicant’s response acceptable because Basis Document BBS-PBD-AMP-XI.E3, “Monitoring and Trending,” program element is revised to specify trending for both testing and inspection. The staff finds that the applicant’s “monitoring and trending” program element is now consistent with the GALL AMP XI.E3, “Monitoring and Trending” program element. The staff’s concern described in RAI B.2.1.39-3 is resolved.

The applicant stated that the LRA AMP B.2.1.39, “Inaccessible Power Cable Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” is a new program that is consistent with GALL Report AMP XI.E3, “Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

The GALL Report AMP XI.E3 states that periodic actions are taken to prevent inaccessible cables from being exposed to significant moisture. Examples of periodic actions are inspecting for water collection in manholes and conduits and then draining water as needed. The inspection should include direct observation that cables are not wetted or submerged, cables/spices and cable support structures are intact, and that dewatering/drainage systems (sump pumps) and associated alarms operate properly. Applicable OE examples noted during the BBS audits and LRA review are described below.

During review of the applicant’s OE, which included work orders and action requests (ARs), the staff identified unresolved cases of water intrusion into manholes and cable vaults which could potentially expose in-scope power cables to significant moisture and/or cable submergence.

In 2011, the applicant found the water level to be approximately 5 feet deep when manhole 0B2 (Byron Station) was opened for yearly inspection. Most of the cables in the manhole were submerged. The applicant’s corrective action was to revise the preventive maintenance inspection from 1 year to 3 months. In their evaluation of this AR, the applicant stated that the short term submergence of these cables will not affect cable function and that these cables are suitable for installation in either wet or dry locations and were tested for long-term submergence.

Preventive maintenance inspections performed on Aug. 15, 2013, noted no water in manhole 0B2 (Byron Station). A followup inspection was performed on Aug. 26, 2013, as a result of heavy rainfall of 2.5 in. in the local area. The applicant noted that water was found approximately 4 feet deep in manhole 0B2. The applicant also stated that based on cable condition trending from 2007, this was the second time cables were submerged in manhole 0B2. The applicant initiated an AR and concluded in its evaluation that these cable were tested by the manufacturer for submergence.

The staff also noticed that during its audit and LRA review of BBS OE, Braidwood has experienced manhole and cable vault degradation including cable support structure degradation, water intrusion, and cable submergence.

The staff is concerned that the applicant's manhole inspections and corrective actions may not be adequate to prevent in-scope inaccessible power cables from being subjected to significant moisture. The staff could not determine, based on BBS OE, whether the applicant's LRA AMP B.2.1.39 would ensure that in-scope inaccessible power cables will continue to perform their intended function during the period of extended operation.

By letter dated January 22, 2014, the staff issued RAI B.2.1.39-4 requesting that the applicant provide the following.

- Describe the corrective actions (e.g., inspection, preventive maintenance) taken to ensure the reliable operation of cable manhole/vault sump pumps to prevent exposure of inaccessible power cables to significant moisture.
- For inaccessible power cables subjected to submergence (significant moisture), describe the inspections and testing performed and acceptance criteria used to establish the condition and operability of these cables as part of the corrective action to ensure that these cables remain capable of performing their intended function consistent with the CLB. Include in the discussion how the interval to inspect for water intrusion of vaults/manholes, vaults/manhole structures, and cable supports is established and adjusted for plant-specific and industry OE.
- Include a discussion of the implementation schedule for corrective actions, including those items already completed for both Byron and Braidwood.

In its response dated February 19, 2014, the applicant described the corrective actions (e.g., inspection, testing, and preventive maintenance) taken to prevent exposure of inaccessible power cables to significant moisture.

For Byron, the applicant stated that there are no permanent sump pumps installed in the in-scope cable vaults at Byron. The applicant also stated the Byron utilizes direct visual inspections in conjunction with manual pumping actions (as appropriate) to prevent exposure of inaccessible power cables to significant moisture. The applicant further stated, as noted by the staff in the background section of the RAI, Byron cable vault 0B2 has recently experienced an adverse trend with regard to water intrusion after a significant rainfall. This OE and associated corrective actions are also addressed in the applicant's response.

Braidwood identified only one in-scope power cable. The applicant provided an assessment of OE stating that with operable cable vault sumps, the in-scope cable is not subjected to significant moisture. As described by the applicant, and confirmed by the staff during the audit, the cable vault sump pumps include controllers with local trouble alarms and alarms for high water level with alarm conditions entered in to the CAP. In addition, to the controller alarms, the applicant clarified that Braidwood currently relies on monthly direct visual inspections of the in-scope cable vaults with a limiting inspection interval of at least once a year. The applicant stated that with installed sump pumps and direct visual inspection, the in-scope cable has not been exposed to significant moisture. The applicant also stated that a 36-month preventive maintenance schedule has been established for the cable vault sump pumps.

The applicant stated for BBS, industry and actual plant OE, including actual plant cable vault inspection trending data, is considered in the determination of individual cable vault direct visual inspection intervals. The applicant also stated that the intervals for direct visual inspection of in-scope cable vaults will not exceed 1 year based on current industry best practices and GALL Report AMP XI.E3. In addition, the applicant stated that based on actual cable vault inspection trending, direct visual inspections of the cable vaults may also be made in response to anticipated or actual adverse weather conditions that may cause water intrusion into the cable vaults. The applicant also provided acceptance criteria and the corrective actions taken if acceptance criteria are not met.

In addition to BBS cable vault inspections, the applicant also stated that inaccessible in-scope power cables subjected to significant moisture are tested at least every 6 years with the results documented and trended. The applicant further stated that a review of current plant OE did not identify any in-scope inaccessible power cable failures for BBS.

The applicant provided information on current Byron operating term initiatives including testing and inspections activities. The applicant stated that 19 of 23 in-scope cables have been tested with 3 more tests scheduled for 2014 with the remaining Byron Station in-scope inaccessible power cable tests scheduled for 2018. The applicant further stated that all tested cables met the acceptance criteria.

According to the applicant, Byron outdoor annual safety-related cable vault inspection activities were first initiated in 2003 in response to industry OE with the scope of the inspection expanded to indoor safety-related cable vaults in 2007 based on actual plant OE. The applicant also stated that annual visual inspection of nonsafety-related cable vaults at Byron were started in 2010 in response to industry OE. These initial inspections identified water intrusion in cable vaults. The applicant further stated that refurbishment of cable vaults started in 2011 with refurbishment of the remaining cable vaults scheduled for completion in 2014.

The applicant stated that Byron in-scope inaccessible power cables in 15 of 16 cable vaults have not been found submerged since the applicant initiated cable vault inspections and pumping in 2010. The applicant also provided a discussion and the corrective actions taken to address in-scope cable submergence found during the August 26, 2013, inspection of cable vault 0B2. The applicant inspected cable vault 0B2 again on September 3, 19, and 25, 2013, and again on October 5, 2013, with the inspections performed after rainfall. Only minor water accumulation was found during the September 25, 2013, inspection. However, the October 5, 2013, inspection of cable vault 0B2 found cables submerged. The applicant entered the condition in the CAP and the water was removed from the vault. The applicant stated that additional inspections were performed after rain fall on November 3, 7, and 11, 2013, and on

December 3, 2013, with no water found in the cable vault. The applicant further stated that a work order is planned to limit surface water intrusion into vault 0B2 and the inspection interval was increased to once per month and after significant rain fall.

For the in-scope cable at Braidwood, the applicant stated the in-scope cable has been tested three times since 2003 with all tests meeting acceptance criteria. The applicant stated that testing will continue with testing planned to be performed every 6 years. The applicant further stated that test frequency may be adjusted based on data trending of test results.

The applicant determined that there are no safety-related cable vaults installed at Braidwood Station. The applicant stated that visual inspection of nonsafety-related cable vaults began in 2008. The applicant found that vault 1E had significant cracks and loose concrete caused by thermal expansion, moisture intrusion, and freeze thaw cycles. The applicant has scheduled repairs with completion in 2014. The applicant refurbished cable vaults subjected to high rates of water intrusion in 2012 and 2013 with sump pumps and high level alarms. The applicant noted that since vault refurbishment in-scope cables have not been submerged.

The staff finds the applicant's response acceptable because the applicant has provided additional information on preventive maintenance actions to maintain reliable operation of installed sump pumps, provided additional information on cable submergence including inspection, testing, and acceptance criteria. The applicant described corrective actions including using industry and plant-specific OE to adjust test and inspection intervals. The applicant provided the implementation schedule for cable vault inspections, refurbishment, and in-scope inaccessible cable testing. The staff finds the revisions to LRA AMP B.2.1.39, "Inaccessible Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," Commitment No. 39, "Inaccessible Power Cables Not Subject to 50.49 Environmental Qualification Requirements," and the applicant's Basis Document BBS-PBD-AMP-XI.E3 consistent with the GALL Report AMP XI.E3. The staff's concern described in RAI B.2.1.39-4 is resolved.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.39-1, B.2.1.39-2, B.2.1.39-3, and B.2.1.39-4, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E3.

Operating Experience. The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

LRA Section B.2.1.39 summarizes OE related to the applicant's new condition monitoring program LRA AMP B.2.1.39, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant provided examples of plant-specific OE showing that BBS have not experienced in-scope inaccessible or underground power cable testing failures at BBS. The applicant provided additional OE examples including the evaluation and incorporation of applicable industry OE, inaccessible cable inspection and testing practices, and corrective action evaluations, including extent of condition, repair, or replacement.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program. The staff reviewed recent integrated inspection reports

(February 9, 2009, May 13, 2009; November 8, 2012; May 14, 2010; October 9, 2013; and August 14, 2013) for inspection findings concerning in-scope manhole and inaccessible cable. No findings were noted for manholes or cable submergence. In addition, during the audit the staff walked down in-scope BBS manholes confirming locations, labeling, cover integrity and susceptibility to surface water runoff. The staff reviewed corrective actions documenting manhole inspection findings including water in cable vaults and cable submergence. Corrective actions taken include water removal, revised inspection frequencies, cable test guidance, cable vault refurbishment, and the development of a modification package and associated work orders to install sump pumps, and limit surface water intrusion.

The staff reviewed the applicant's response to Generic Letter (GL) 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which requested, in part, licensees provide a history of inaccessible or underground power cable failures. The applicant's response for BBS stated that within the scope of 10 CFR 50.65 no history of failures of inaccessible or underground power cables was noted (voltage range of 480 Vac to 1.5k Vac).

Based on its audit, review of the application, and review of the applicant's responses to RAIs B.2.1.39-1, B.2.1.39-2, B.2.1.39-3 and B.2.1.39-4, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.E3 was evaluated.

UFSAR Supplement. LRA Section A.2.1.39 provides the UFSAR supplement for the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The applicant committed to implement the new Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements for managing the effects of aging for applicable components prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Fuse Holders (Byron Only)

Summary of Technical Information in the Application. LRA Section B.2.1.41 describes the new Fuse Holders Program as consistent with GALL Report AMP XI.E5, "Fuse Holders." The applicant stated that the fuse holder program applies to metallic portions of fuse holders within the scope of license renewal located outside of active devices that are susceptible to increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent manipulation, or vibration. The applicant also stated that fuse holders subject to increased resistance of connection or fatigue will be tested, by a proven test methodology, such as thermography, contact resistance testing, or other appropriate testing method, at least once every 10 years for indications of aging degradation and will be implemented prior to the period of extended operation. Further, the applicant stated that visual inspection is not part of the program. Finally, the applicant stated that no fuse holders at Braidwood are required to be managed by this AMP because there are no in-scope fuse holders located outside of active devices susceptible to aging effects at Braidwood.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.E5. As part of its audit, the staff interviewed the applicant's staff and reviewed onsite Byron and Braidwood documentation provided by the applicant. The staff also conducted an independent search of the applicant's Byron and Braidwood OE database.

During the audit of program elements 1 through 6, the staff confirmed the applicability of GALL Report AMP XI.E5, "Fuse Holders" to only Byron Station and that the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending," program elements of the LRA AMP are consistent with the corresponding elements of the GALL Report AMP.

For the "acceptance criteria" program element sufficient information was not available to determine whether it was consistent with the corresponding program elements of the GALL Report AMP. In order to obtain the information necessary to verify whether this program element is consistent with the corresponding program element of the GALL Report AMP, the staff issued an RAI for the subject discussed below.

The GALL Report AMP XI.E5, "Fuse Holders," recommends the acceptance criteria for each test are defined by the specific type of test performed and the specific type of fuse holder tested. The temperature of the metallic clamp of the fuse holder needs to be below the maximum allowed temperature for the application when thermography is used; otherwise, a low resistance value appropriate for the application when resistance measurement is used. However, during its audit, the staff found that for applicant's Fuse Holders (Byron Only) Program the "acceptance criteria" program element of the applicant's program Basis Document states:

> The acceptance criteria for each test are defined by the specific type of test performed and the specific fuse holder application. The thermography program establishes acceptance criteria for thermography test. When thermography is not practical, other acceptable tests are implemented, such as connection resistance measurement. Acceptance criteria are set in accordance with good practice.

Acceptance criteria set "in accordance with good practice" is unclear and inconsistent with the guidance of the GALL Report. A clear acceptance criterion needs to be established in order for the applicant to take appropriate corrective action. Acceptance criteria consistent with the GALL Report ensures that the intended function of the metallic portion of fuse holders can be maintained consistent with the current license basis during the period of extended operation. By letter dated January 13, 2014, the staff issued RAI B.2.1.41-1 requesting the applicant to clarify why establishing acceptance criteria "in accordance with good practice," is consistent with the GALL Report guidance and not an enhancement or exception.

In its response dated February 4, 2014, the applicant revised the AMP Basis Document "acceptance criteria" program element to be consistent with the GALL Report. The applicant revised the Fuse Holders (Byron only) Program acceptance criteria as shown below.

> The acceptance criteria for each test are defined by the specific type of test performed and the specific fuse holder application. Acceptance criteria are included in controlled station procedures or work orders. The thermography program establishes acceptance criteria for thermography tests; specifically the metallic clamp of the fuse holder needs to be below the maximum allowed temperature for the application as defined by the thermography program procedures. When thermography is not practical, other acceptable tests are implemented, such as connection resistance measurement. The acceptance criterion for testing fuse holders is defined by the specific type of test chosen. For example, a connection resistance acceptance criterion is established by using a low resistance value appropriate for the application. The established acceptance criteria ensures corrective actions are taken in accordance with the corrective action program when the acceptance criteria are not met so that the intended function of the fuse holders are maintained consistent with the current licensing basis.

The staff finds the applicant's response acceptable because the applicant's AMP Basis Document "acceptance criteria" program element is now consistent with the "acceptance criteria" program element of GALL AMP XI.E5. Specifically, the applicant's AMP acceptance criteria are included in station procedures, and a more specific acceptance criterion is established for thermography tests. The staff's concern described in RAI B.2.1.41-1 is resolved.

Based on its audit and review of the applicant's responses to RAI B.2.1.41-1, the staff finds that the program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E5, "Fuse Holders" (Byron only).

<u>Operating Experience</u>. LRA Section B.2.1.41 summarizes OE related to the Fuse Holders (Byron Only) AMP. The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

Although the Fuse Holders (Byron Only) is a new program, the applicant currently employs testing, inspection, thermography, and OE review for electrical components. During its review of OE, the staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.E5, "Fuse Holders," was evaluated.

UFSAR Supplement. LRA Section A.2.1.41 provides the UFSAR supplement for the applicant's Fuse Holders (Byron Only) AMP. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the new Fuse Holder (Byron Only) Program, including initial tests, for managing the effects of aging for applicable components prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Fuse Holders (Byron Only) Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.42 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL Report AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The LRA also states that the AMP addresses a representative sample of electrical connections within the scope of license renewal, which are tested at least once prior to the period of extended operation to confirm that there are no AERM. Additionally, the applicant stated that testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation such as heat shrink tape, sleeving, insulating boots, etc. Further, the applicant stated the one-time test provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures and that existing installation and maintenance practices are effective.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.E6.

For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.E6 recommends that a representative sample size is 20 percent of the population with a maximum sample of 25 connections. However, during its audit, the staff found that the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program could allow the applicant to select a sample size/methodology that is inconsistent with the guidance of GALL Report AMP XI.E6. GALL Amp XI.E6 states that for alternate sampling methodologies a technical justification of the methodology and sample size used for selecting components for one-time test should be included as part of the AMP's site documentation. By letter dated January 13, 2014, the staff issued RAI B.2.1.42-1 requesting that the applicant clarify if the sample size selection is consistent with GALL Report AMP XI.E6 recommendation. If the sample size was different than the GALL Report, the staff requested that the applicant provide a technical justification of the methodology and sample size used for selecting components.

In its response dated February 4, 2014, the applicant stated that:

> The representative sample size selection for LRA AMP B.2.1.42, 'Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,' is twenty percent of the population with a maximum sample of 25 connections. This is consistent with the GALL Report AMP XI.E6 recommendation. Since the basis of the sample selected is aligned with the GALL Report AMP XI.E6 recommendation, additional documentation of the technical basis for the sample selected is not required to be documented per station procedures.
>
> The detection of aging effects program element of the site AMP Basis Document for LRA AMP B.2.1.42, 'Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,' is revised to clarify that the 'detection of aging effects' program element is consistent with the GALL Report. The detection of aging effects program element of the site AMP Basis Document now states:
>
>> A representative sample of electrical cable connections within the scope of license renewal will be tested prior to the period of extended operation to confirm there are no aging effects requiring management during the period of extended operation. The type of test or inspection to be performed will be a proven test for detecting increased resistance of connections such as thermography, contact resistance testing or other appropriate quantitative test methods without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc. This one-time test provides additional confirmation to support industry operating experience demonstrating electrical connections have not experienced a high degree of failures and that existing installation and maintenance practices are effective. A representative sample size is twenty percent of the population with a maximum sample of 25 connections.

The staff finds that the "detection of aging effects" program element of the site AMP Basis Document for LRA AMP B.2.1.42, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," is consistent with GALL Report XI.E6. The staff finds the applicant's response acceptable because the change to LRA AMP B.2.1.42 made the program consistent with GALL Report AMP XI.E6. The staff's concern described in RAI B.2.1.42-1 is resolved.

Based on its audit and its review of the applicant's response to RAI - B.2.1.42-1, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E6.

<u>Operating Experience</u>. LRA Section B.2.1.42 summarizes OE related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

For Byron Station, the applicant stated:

> In September 2009, operations personnel noticed changing conditions associated with the Unit 2 group D pressurizer heaters. Investigation by operations personnel determined that two 480 Vac MCC breakers, which feed pressurizer heaters A6A and A2B, were tripped open. The breakers were reset and the issue was entered into the corrective action program. Troubleshooting by maintenance personnel identified loose connections of the cable terminated to the load side of the breaker feeding the A2B heater. The connections were tightened and thermography was performed to ensure the integrity of the connections. No cause was identified for the breaker feeding A6A heater. An extent of condition evaluation and operational experience search revealed previous similar events with poor/loose connections associated with pressurizer heater MCC breakers. To determine the cause of the breaker trips, a common cause evaluation (CCA) was performed by the system manager, who investigated a total of eleven (11) issues associated with tripped pressurizer heater breakers. The CCA determined that installation deficiencies were causing the increased failure rate of these breakers. Installation deficiencies included lugs not being captured by the screw connecting the lug to the breaker terminal, insufficient lug crimps, nutserts installed incorrectly, and looseness in lug connections resulting in nonflush connections. Each of these deficiencies led to high resistance connections, which resulted in premature breaker trips. In addition, the CCA determined that the majority of the installations with deficient connections were performed by a personnel working for a particular site maintenance contractor company. Corrective actions were initiated to correct the installation deficiencies, address extent of conditions, provide lessons learned in training programs, and revise procedures to preclude future issues.

The applicant also stated that:

> In July 2004, during performance of routine thermography, maintenance personnel identified a warm connection on one phase of a 480 Vac contactor associated with the cooling fans of the 2W main power transformer. The issue was entered into the corrective action program. In accordance with thermography procedures, the condition was rated as a Watch List (Blue) level with follow up thermography inspections to be performed weekly for two weeks then increased further if no changes in severity are evident. Several follow up thermography inspections showed no change in the severity of the condition. However, as a conservative measure, the contactor with its associated warm connection was replaced and the thermography temperatures returned to normal. The cause of the warm thermography readings was attributed to a high resistance connection on one phase of the contactor.

For Braidwood Station, the applicant stated that:

> In March 2007, during routine thermography inspections, it was discovered that the temperature of the upper connection of a fuse block in Rod Drive cabinet 2RD04E was elevated indicating a possible loose connection of the wiring to the fuse block. The discovery was entered into the corrective action program. The issue was evaluated by engineering personnel and determined to not be an immediate concern. Engineering recommended the frequency of

thermography inspections of the fuse and associated connections be increased from semiannually to monthly and trended. A plan was also put in place to replace the wiring connected to the fuse block during the next refuel outage or forced outage. Follow up thermography readings were trended for several months with no significant increase in the temperature of the fuse block connection and the wiring was replaced during the refuel outage. Investigation into the cause of the elevated connections temperatures revealed a defective crimped connection on the wire lug. As part of extent of condition review, other similar Rod Drive fuses in Rod Drive cabinets and associated connections were scanned with thermography. No further issues were discovered.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.E6 was evaluated.

UFSAR Supplement. LRA Section A.2.1.42 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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed (Commitment #42) to implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to the period of extended operation for the management of aging effects of applicable components. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.20 Environmental Qualification (EQ) of Electric Components

Summary of Technical Information in the Application. LRA Section B.3.1.3 describes the existing Environmental Qualification (EQ) of Electric Components Program as consistent with GALL Report AMP XI.E1, "Environmental Qualification (EQ) of Electric Components." The LRA also states that the AMP manages the aging of electrical equipment within the scope of 10 CFR 50.49, “Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants.” Additionally, the applicant stated that the AMP establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance, and replacements necessary to meet 10 CFR 50.49. Further the applicant stated that appropriate actions such as replacement or refurbishment are taken prior to or at the end of the qualified life so that the aging limit of the component is not exceeded. Finally, the applicant stated that aging effects addressed by the LRA Section B.3.1.3 are adequately managed such that the intended functions of components are maintained consistent with the CLB 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 compared program elements 1 through 6 of the applicant’s program to the corresponding program elements of GALL Report AMP X.E1.

In its review and audit of LRA Section TLAA 4.7.3, “Mechanical Environmental Qualification,” and TAB E, “Installation, Maintenance, and Surveillance Schedule” of select BBS Station EQ binders, the staff noticed that per LRA Table 3.2.2-2 and the respective AMR Tables, there is no AERM and that no AMP is recommended. However, the EQ binders include surveillance activities for consumable subcomponents (e.g., O-rings and gaskets) with specific replacement intervals assigned.

Per SRP-LR Table 2.1-3, “Specific Guidance on Screening,” consumables may be divided into the following four categories for the purpose of license renewal: (a) packing, gaskets, component seals, and rings; (b) structural sealants; (c) oil, grease, and component filters; and (d) system filters, fire extinguishers, fire hoses, and air packs. Table 2.1-3 states that categories (a) and (b) are considered subcomponents and are not explicitly called out in the scoping and screening procedures but are implicitly included at the component level. Further, the consumables in category (c) are usually short-lived and periodically replaced and can normally be excluded from an AMR on that basis. Category (d) includes consumables that are typically replaced based on performance or condition monitoring that indicates whether these components are at the end of their qualified life and may be excluded on a plant-specific basis from AMR (10 CFR 54.21(a)(1)(ii). However, TLAA 4.7.3, “Mechanical Environmental Qualification,” addresses component replacement intervals required to maintain mechanical component EQ qualification. Based on the above review and audit, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

By letter dated February 18, 2014, the staff issued RAI 4.7.3-1 requesting that the applicant provide a basis for why the EQ binder subcomponent surveillances included in the mechanical environmental qualification (MEQ) binders are not required to be performed to ensure the qualified life of EQ components and subcomponents are maintained during the period of extended operation as described in TLAA Section 4.7.3.

In its response dated March 4, 2014, the applicant provided an enhancement to LRA AMP B.3.1.3 to include aging management of environmentally qualified mechanical components and subcomponents. The enhancement allows MEQ component and subcomponent aging to be managed during the period of extended operation as described in TLAA Section 4.7.3 with aging management performed under the EQ of Electric Components Program (LRA Section B.3.1.3). The enhancement also included additional changes to the LRA as described below.

- LRA Sections 2.5.2.1, 2.5.2.2, and 2.5.2.4 are revised to identify "mechanical environmental qualification (MEQ) components" as an electrical commodity.
- LRA Section 3.6.2.4 is revised to identify LRA 4.7.3 as the TLAA addressing the "mechanical environmental qualification (MEQ) components" commodity.
- LRA Table 3.6.2-1 is revised to include "mechanical environmental qualification (MEQ) components" as an electrical commodity.
- LRA Section A.1.3 is revised to conform to Section A.3.1.3.
- LRA Section A.3.1.3 is revised to enhance the scope of the EQ of Electric Components AMP to include MEQ components.
- LRA Section B.1.6 is revised to conform to Section B.3.1.3.
- LRA Section B.3.1.3 is revised to enhance the scope of the EQ of Electric Components AMP to include environmental MEQ components.

In addition, the applicant revised its commitment (commitment 45) to expand the scope of the EQ of Electric Components AMP to include MEQ components with the program enhancement implemented prior to the period of extended operation.

In LRA Section B.3.1.3, "Environmental Qualification (EQ) of Electric Components," the applicant provides an enhancement to the "scope of program," and associated program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls." In this enhancement, the applicant's EQ program expands the scope of program to include aging management of MEQ components in addition to electrical component aging management as stated in the GALL Report (i.e., AMP X.E1, "Environmental Qualification (EQ) of Electric Components"). The staff reviewed the enhancement against the corresponding program elements in GALL Report AMP X.E1 and finds it acceptable because a plant-specific TLAA for mechanical components qualified to Criterion 4 of Appendix A to 10 CFR Part 50 was established by the applicant in accordance with SRP-LR Sections 4.4.1 and 4.7. In addition, the expanded scope of LRA Section B.3.1.3 to include aging management of MEQ components is acceptable in that LRA Table 3.6.2-1 identifies the same materials, environments, aging effects requiring aging management for both electrical components environmentally qualified pursuant to 10 CFR 50.49 and mechanical component qualified under Criterion of Appendix A to 10 CFR Part 50. The staff's concern described in RAI 4.7.3-1 is resolved.

Based on its audit and its review of the applicant's response to RAI 4.7.3-1, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E1. In addition, the staff reviewed the enhancement associated with "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls" program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B.3.1.3 summarizes OE related to the EQ of Electric Components GALL Report AMP XI.E1.

For Byron Station, the applicant stated:

In June 2011, a periodic Focused Area Self-Assessment was completed for the Environmental Qualification (EQ) of Electric Components program. The assessment concluded that the EQ Program continues to meet regulatory requirements for documentation, administrative controls, preventive maintenance, procurement, receipt inspection, and personnel knowledge and performance. Several minor deficiencies with the EQ Program related documents were found and entered into the corrective action program.

The applicant also stated:

In March 2006, it was discovered that an EQ requirement regarding the reactor containment fan cooling (RCFC) motors had inadequate maintenance work orders in the work management process. Specifically, the EQ binder states that all RCFC fan motor shaft inboard bearings be replaced prior to exceeding 21.8 years of service. Although there were work orders to replace the shaft inboard bearing, due dates for replacing bearing were not established in the work management process. Thus, there were no work orders scheduled in the work management process to replace the shaft bearings. This issue was entered into the CAP. The investigation determined that none of the RCFC motor inboard shaft bearings exceeded their qualified service life because they all have been in service less than 18 years. The RCFC fan motor shaft bearing work orders were assigned specific due dates and scheduled in the work management process. The extent of condition investigation reviewed other EQ binders and found that they all had work orders with appropriate due dates in the work management process. This confirmed that this issue was limited to only the RCFC motors.

For Braidwood Station, the applicant stated:

In March 2012, a periodic Focused Area Self-Assessment was completed for the Environmental Qualification (EQ) of Electric Components program. The assessment concluded that the EQ Program continues to meet regulatory requirements for documentation, administrative controls, preventive maintenance, procurement, receipt inspection, and personnel knowledge and performance. The results of the assessment were entered into the corrective action program to track recommendations. A performance improvement recommendation was identified to adjust a component replacement frequency in the work management process to better align with the actual service life determined in the component EQ documentation based on as-found field data. The actual operating environment in the field is less severe than the component service life assumed in the EQ program.

The applicant also stated:

In 2004, the hydrogen monitoring system was replaced with new equipment. In February 2012, it was discovered that the work requests for the maintenance work orders to replace the EQ capacitors in the new hydrogen monitoring system were never created in the work management process. This issue was entered into the corrective action program (CAP). The initial investigation determined that the capacitors were installed between October and December 2004 as part of the modification to replace the hydrogen monitoring system with a new system. Capacitors in the new hydrogen monitoring system have a qualified life of 11.44 years from the date of installation. Therefore, the capacitors had not exceeded their qualified life since they have been installed for approximately 7 years at the time of discovery. The followup extent of condition investigation consisted of a 100 per cent review of the EQ maintenance work orders for all of the hydrogen monitoring system components as well as other modification packages completed in 2004. No other issues were found. This confirmed that this issue was limited to only the EQ capacitors in the new hydrogen monitoring system. The maintenance work order requests to replace the EQ capacitors in the new hydrogen monitoring system were created with an 11-year frequency and a due date of 4/15/2014 based on the installation date of the new hydrogen monitoring system.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff found no OE to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP X.E1 was evaluated.

UFSAR Supplement. LRA Section A.3.1.3 provides the UFSAR supplement for the Environmental Qualification (EQ) of Electric Components Program. The staff reviewed the UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, and the EQ of mechanical components guidance in SRP-LR Sections 4.4 and 4.7. The staff also noticed that the applicant committed (Commitment 45) to implement the existing Environmental Qualification (EQ) of Electric Components Program, with enhancement, for managing the effects of aging for applicable environmentally qualified mechanical components prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

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

3.0.3.2 AMPs Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Reactor Head Closure Stud Bolting
- PWR Vessel Internals
- Bolting Integrity
- Steam Generators
- Open-Cycle Cooling Water System
- Closed Treated Water Systems
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Compressed Air Monitoring
- Fire Protection
- Fire Water System
- Aboveground Metallic Tanks
- Fuel Oil Chemistry
- Reactor Vessel Surveillance
- Buried and Underground Piping
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWL
- ASME Section XI, Subsection IWF
- Masonry Walls
- Structures Monitoring
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Protective Coating Monitoring and Maintenance Program
- Metal Enclosed Bus
- Fatigue Monitoring
- Concrete Containment Tendon Prestress

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

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.1, as revised by letters dated June 18, 2014, August 29, 2014, and February 11, 2015, describes the applicant's existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as consistent with enhancements with GALL Report AMP XI.M1. The LRA states that the program manages loss of material, cracking, thermal embrittlement, flaw growth, and reduction in fracture toughness for ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting using volumetric, surface, and/or visual examinations and leakage testing, as specified in ASME Section XI Code, 2001 Edition through the 2003 Addenda.

In addition, the LRA states that limitations, modifications, and augmentations described in 10 CFR 50.55a are included as a part of this program. The LRA further states that the program is updated each successive 120-month inspection interval to the latest ASME Section XI Code Edition and Addenda approved by the staff in 10 CFR 50.55a 12 months before the start of the inspection interval. The LRA also states that repair and replacement activities for these components are covered in Subsection IWA of the ASME Code of record. The LRA further states that the ISI program is consistent with the program described in the GALL Report, Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." The LRA also enhanced the program with a visual inspection of the accessible portions of the ASME Class 2 reactor vessel flange leakage monitoring tube every other refueling outage.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M1. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL Report AMP XI.M1.

The "detection of aging effects" program element in GALL Report AMP XI.M1 states that components are examined and tested as specified in ASME Code Section XI, Tables IWB-2500-1, IWC-25001, and IWD-2500-1, for Code Class 1, 2, and 3 components, respectively. The staff noticed that the applicant implemented risk-informed inservice inspection (RI-ISI), as an alternative to the inspection requirements of the Class 1 and 2 piping welds for Units 1 and 2. The staff also noticed that the use of RI-ISI Program is only approved for the current third 10-year ISI interval. Future implementation of the RI-ISI is subject to NRC approval in accordance with 10 CFR Part 50.55a for each subsequent 10-year ISI interval, including the period of extended operation. The staff confirmed during the onsite audit that the applicant's ISI program plan includes a review of the current RI-ISI implementation, prior to submitting future relief requests for NRC approval. The staff finds this acceptable because the applicant will have to seek NRC approval for its proposed use of its alternative RI-ISI Program for future inspection intervals, including for the period of extended operations.

The staff also reviewed the portion of the "scope of program" program element associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.1 includes an enhancement to the "scope of program" program element. The applicant stated that prior to the period of extended operation it will enhance the "scope of the program" program element to include a visual inspection of the accessible portions of the ASME Class 2 reactor vessel flange leakage monitoring tube, every other refueling outage. The staff reviewed this enhancement against the corresponding program element in the GALL Report AMP XI.M1 and finds it acceptable because when the enhancement is implemented, it will perform additional and more frequent inspections, and will provide additional assurance that aging effects, if any, will be detected before loss of intended function.

Enhancement 2. LRA Section B.2.1.1 as revised by letter dated February 11, 2015, includes an additional enhancement to the "scope of program" program element. The applicant stated that it will perform NDEs of all five centermost CRDM nozzles prior to the period of extended operation, and on a 10-year frequency during the period of extended operation. The applicant proposed this enhancement as a result of staff's review of LRA Section B.2.1.5. The staff's review of this enhancement is documented in SER Section 3.0.3.1.3.

Based on its audit and review of the applicant's ASME Section XI ISI, Subsections IWB, IWC, and IWD Program, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M1. The staff also reviewed the enhancements associated with the "scope of program" program element and finds that when implemented it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.1 summarizes OE related to the applicant's ISI program and provides specific examples of the applicant's OE. In one of the cases related to the Braidwood Unit 1, 2012 refueling outage, the applicant stated that a planned UT inspection detected an indication in its vessel head penetration number 69. It characterized the defect as PWSCC based on program procedures. The applicant subsequently performed corrective actions to repair the penetration and performed extent of condition examinations to determine the condition of similar components. The plant-specific OE demonstrates that the ISI program is effective in identifying age-related degradation and that the CAP is effective in implementing corrective actions to maintain component intended functions.

The LRA section also states that, during the Braidwood Unit 1, 2006 refueling outage, boric acid leakage was discovered originating from the number 52 pressurizer heater near the upper weld between the pressurizer heater sleeve and heater coupling which resulted in a limiting condition for operation. The condition was entered into the CAP. The degraded component was repaired using an engineered ASME Code Section III repair procedure. The applicant also performed a root cause analysis to identify the causal factors followed by extent of condition review and appropriate corrective actions.

The LRA section provides four cases of the applicant's plant OE related to the ISI program. During the audits, the staff also reviewed additional cases of the applicant's plant-specific OE. The staff noticed that the OE provided by the applicant illustrates specific examples of the capability and effectiveness of the applicant's ISI program in detecting and addressing the aging effects. Specifically, the applicant's program is effective in identifying indications and flaws, and when detected flaws are found to exceed the Code allowable flaw size, the flaws either are repaired or are evaluated by analytical methods for continued operation, as allowed by ASME Code Section XI, Section IWB-3600. These cases demonstrate that the applicant's ISI program is effective in identifying age-related degradation and that the CAP is utilized to evaluate degraded conditions and implement corrective actions to maintain the intended functions of plant systems and components.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would 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 its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking appropriate corrective actions. In addition the staff finds that the conditions and OE at the plant are bounded by those for which the GALL Report AMP XI.M1 was evaluated.

UFSAR Supplement. LRA Section A.2.1.1, as amended by letters dated June 18, 2014, and August 29, 2014, and February 11, 2015, provides the UFSAR supplement for the ISI program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's ISI program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 Reactor Head Closure Stud Bolting

Summary of Technical Information in the Application. LRA Section B.2.1.3 describes the existing Reactor Head Closure Stud Bolting Program as consistent with GALL AMP XI.M3, "Reactor Head Closure Stud Bolting," with an exception and an enhancement. The LRA states that the Reactor Head Closure Stud Bolting Program is based on the examination and inspection requirements specified in the ASME Section XI Code, Subsection IWB, Table IWB-2500-1, and manages the aging effects of an air with borated water leakage environment for reactor head closure studs washers, nuts, and flange threads. The LRA also states that the program includes preventive measures described in NRC NUREG–1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure of Nuclear Power Plants," and NRC RG 1.65, "Materials and Inspection for Reactor Vessel Closure Studs."

The LRA states that the RPV head flange threads and studs receive a volumetric examination and the surfaces of the nuts and washers are inspected using volumetric testing (VT)-1 examinations. The applicant stated that these pressure boundary retaining components also receive a VT-2 examination during the system leakage test and the system hydrostatic test.

The LRA states that based on documentation, some reactor head closure studs may have actual measured yield strength that is greater than 150 ksi. The LRA also states that since the actual measured yield strength of some installed studs may be greater than 150 ksi, the AMR identified the stud material as "High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater" and identified cracking as an AERM.

The LRA further states that prior to the period of extended operation, the "preventive measures" and "corrective actions" program elements will be revised to ensure that the procurement requirements for reactor head closure stud material specifically state that the maximum yield strength of replacement studs be limited to a measured yield strength less than 150 ksi.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M3. As discussed in the audit report, during review of the "operating experience" program element the staff found that the applicant's OE was not bounded by known industry experience.

Specifically, Byron Unit 2 stud No. 11 became stuck in 2010, with insufficient thread engagement to be tensioned. The applicant decided to abandon the stuck stud in place, after cutting approximately 5 in. from the top end of the stuck stud. As a result, the remaining portion of stud No. 11 and its flange hole are exposed to borated water during refueling outages and are inoperable.

In addition, Braidwood Unit 2 stud No. 35 became stuck in 1991. However, the stuck stud had enough thread engagement and was fully tensioned during operations until May of 1994, when the stud was cut at the flange level to facilitate fuel movement activities. In 2002, the applicant initiated repair activities in an effort to restore operability to stud No. 35. The remnant of the stuck stud was bored out. However, during machining operations the flange stud hole was overbored due to an error. Further efforts to restore the threads to stud hole no. 35 were suspended; as a result, since 2002 Braidwood Unit 2 stud hole no. 35 is exposed to borated water during refueling outages and is inoperable.

The staff noticed that in LRA Section B.2.1.3, the applicant stated that its Reactor Head Closure Stud Bolting Program is consistent, with GALL AMP XI.M3, "Reactor Head Closure Stud Bolting," with an exception and an enhancement. The staff also noticed that the Abstract for the GALL Report states that:

> An applicant may reference the GALL Report in an LRA to demonstrate that the programs at the applicant's facility correspond to those reviewed and approved in the GALL Report. The GALL Report should be treated as an approved topical report. However, if an applicant takes credit for a program in the GALL Report, it is incumbent on the applicant to ensure that the conditions and operating experience at the plant are bounded by the conditions and operating experience for which the GALL Report program was evaluated. If these bounding conditions are not met, it is incumbent on the applicant to address the additional effects of aging and augment the GALL Report AMP(s) as appropriate.

The staff further noticed that the applicant's discussion of its plant-specific OE in the LRA did not fully address how the applicant's plant-specific OE and conditions are bounded by industry OE and conditions. The staff is concerned that a generic AMP may not be applicable in light of the unique conditions at Byron Unit 2 and Braidwood Unit 2.

By letter dated October 7, 2013, the staff issued RAI B.2.1.3-2 requesting that the applicant justify how its plant-specific OE is bounded by the industry OE as considered in GALL Report AMP XI.M3. The staff also requested, as an alternative, that the applicant either provide revisions to the program with adequate technical bases, or provide a plant-specific AMP to manage aging effects of the reactor closure studs.

In its response dated November 5, 2013, the applicant stated that during the development of its AMP (B.2.1.3), a review of plant-specific OE confirmed that GALL Report AMP XI.M3 is adequate to manage the aging effects at BBS. The applicant also stated this review identified the plant-specific OE related to Byron Unit 2 stud No. 11 and Braidwood Unit 2 stud hole no. 35, but it was dispositioned as not age-related. The applicant further stated that upon additional review, it was determined that the configuration at Byron Unit 2 with an untensioned closure stud left in place during refueling outages was not considered in the GALL Report AMP XI.M3.

The applicant stated that the 10 elements of GALL Report, Revision 2, XI.M3 were then reviewed to determine if augmentation of the program is required to adequately address the configurations specific to Byron and Braidwood. The applicant also stated that the Reactor Head Closure Stud Bolting Program implementing procedures were also reviewed to determine whether existing program procedures fully address Byron and Braidwood's plant-specific OE and fully address aging management of Byron Unit 2 stud No. 11 and Braidwood Unit 2 stud hole no. 35, or whether enhancements to the existing program are required. The applicant further stated that based on this review, it was concluded that an additional enhancement to the Byron and Braidwood Reactor Head Closure Stud Bolting (B.2.1.3) AMP is needed to ensure adequate aging management of the reactor head closure studs and associated components during the period of extended operation.

The applicant stated that with the addition of the new enhancement, the existing program procedures and the enhancement previously described in the LRA fully address Byron and Braidwood's plant-specific OE and the configuration of Byron Unit 2 stud No. 11 and Braidwood Unit 2 stud No. 35. As part of its response, the applicant provided a summary of its evaluation of the 10 elements for GALL Report AMP XI.3M and amended its program in an effort to address its plant-specific OE and the configuration of the Byron Unit 2 stud No. 11 and the Braidwood Unit 2 stud No. 35. The applicant amended LRA Sections B.2.1.3 and A.2.1.3 and LRA Table A.5 Commitment No. 3 to reflect the new enhancement.

During the audit of Byron Station, the staff noticed that the threads of the stuck stud No. 11 for Unit 2 are not leak-tight, and borated water may enter into the flange hole bottom space during refueling outages. The staff also noticed that the boric acid concentration may continually increase following each refueling outage and subsequent plant heatup; therefore, accelerated boric acid corrosion could occur and may go undetected.

By letter dated October 7, 2013, the staff issued RAI B.2.1.3-3 requesting that the applicant address the condition of stud No. 11 and the associated flange hole and explain how its AMP will detect and monitor boric acid corrosion for stud No. 11 and its flange hole.

In its response dated November 5, 2013, the applicant stated that stud No. 11 is exposed to borated water during refueling outages, and there is a potential for borated water to migrate past the stud threads and accumulate in the stud hole (studs have a 1 in. center bored hole) and the empty space under the stud.

The applicant stated that the potential for boric acid corrosion in these areas is insignificant, and has been evaluated and is bounded by analyses. The applicant further stated that this conclusion is based on the short interval when these areas are exposed to borated water during refueling outages; as part of its response, the applicant provided a summary of its analyses.

The applicant stated that its enhancements to its program in response to RAI B.2.1.3-2, will require ultrasonic examination of the Byron Unit 2 stud No. 11 flange hole each refueling outage, while the stud remains out of service. The applicant also stated that an NRC inspection took place on the week of October 28, 2013, related to Byron Unit 2 operating with 53 reactor head closure studs. The applicant further stated that as a result of this inspection some issues were identified that required further evaluation (currently in progress) and were entered into the applicant's CAP. The applicant stated that when these evaluations are complete, it will inform NRC of any impact on its RAI response.

By letter dated December 19, 2013, the applicant amended its response to RAIs B.2.1.3-2 and B.2.1.3-3. In its revised response to RAI B.2.1.3-2, the applicant stated that it will perform repairs to address the current plant-specific operating conditions at Byron Unit 2 and Braidwood Unit 2. The applicant stated that the repairs of Byron Unit 2 reactor head closure stud No. 11 and Braidwood Unit 2 stud hole no. 35 would allow for all 54 reactor head closure studs to be fully tensioned prior to the period of extended operation.

The applicant stated that Byron Unit 2 stud No. 11 will be removed and the reactor vessel flange stud hole threads will be inspected and repaired, if required. The applicant also stated that Braidwood Unit 2 stud hole no. 35 will be repaired. The applicant further stated that the repairs will be completed no later than 6 months prior to the period of extended operation. The applicant stated that these actions will provide an opportunity for the staff to review completion of the related repairs prior to Byron Unit 2 and Braidwood Unit 2 entering the period of extended operation.

As part of its revised response, the applicant amended LRA Sections A.2.1.3 and B.2.1.3 to delete the enhancement that was added in the original RAI response, dated November 5, 2013, since all four Byron and Braidwood units will be operated with all 54 studs tensioned during the period of extended operation. In addition, the applicant also revised its LRA Table A.5 Commitment No. 3 and deleted the enhancements which were added by the original RAI response dated November 5, 2013. The applicant further revised its LRA Table A.5 Commitment List to add Commitment No. 47, to capture the new commitment to repair the Byron Unit 2 stud location no. 11; and Commitment No. 48 to capture the new commitment to repair Braidwood Unit 2 stud location no. 35.

Commitment No. 47 states, "Byron Unit 2 reactor head closure stud location 11 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation." The applicant reported later (by letter dated January 23, 2015) that Commitment No. 47 was completed, as discussed and evaluated below.

Commitment No. 48 states, "Braidwood Unit 2 reactor head closure stud location 35 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation."

The staff found at that time that the applicant's response to RAI B.2.1.3-2, dated December 19, 2013, was acceptable because the implementation of Commitments Nos. 47 and 48 prior to the period of extended operation will address the staff's concern related to the unique configuration of the Byron Unit 2 stud No. 11's being stuck and inoperable, as well as that of Braidwood Unit 2 stud No. 35 stud hole's being inoperable. Commitment No. 47 was reported complete as discussed below. In order to ensure that the Braidwood Unit 2 inoperable stud location is restored so that all 54 reactor head closure studs are tensioned during the period of extended operation, the staff will consider incorporating the applicant's Commitment No. 48 into a license condition. Therefore, the staff's concerns described in RAI B.2.1.3-2 are resolved.

In its revised response to RAI B.2.1.3-3, the applicant stated that its revised response to RAI B.2.1.3-2 documented that the Byron Unit 2 stud No. 11 will be removed, the reactor vessel flange stud hole threads will be inspected, and, if a repair is required, the stud hole will be repaired. The applicant also stated that prior to the period of extended operation the condition of the stud hole will be known, and the area will be accessible for inspection during refueling outages. The staff finds the applicant's response to RAI B.2.1.3-2 also addresses the staff's concerns expressed in RAI B.2.1.3-3, because through the implementation of applicant's

Commitment No. 47, stud No. 11 will be removed, the reactor vessel flange stud hole threads will be inspected and repaired as necessary. In addition, this repair would make the stud hole accessible for inspections during refueling outages during the period of extended operation. The staff's concerns expressed in RAI B.2.1.3-3 are resolved.

By letter dated January 23, 2015, the applicant provided an update on the completion of Commitment No. 47, which states, "Byron Unit 2 reactor head closure stud location 11 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation." The applicant stated that the Byron Unit 2 partially stuck stud No. 11 was removed during the fall 2014 refueling outage. The applicant also stated that the stud hole was cleaned and that there were no signs of thread damage on the stud or flange hole threads. The applicant further stated that the stud hole was evaluated and determined acceptable for use after minor cleanup. The applicant also stated that a new stud was installed at this location, and therefore, its Commitment No. 47 is completed. As part of its update, the applicant revised LRA Section B.2.1.3 and LRA Appendix A, Table A.5, "License Renewal Commitment List," consistent with its update.

In order to ensure that the Braidwood Unit 2 inoperable stud location (No. 35) is restored so that all 54 reactor head closure studs are tensioned during the period of extended operation, the staff has proposed incorporating applicant's Commitment No. 48 into a license condition.

The staff reviewed the portions of the "preventive actions" and "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.2.1.3 includes an exception to the "preventive actions" program element. The applicant stated that site documentation indicates that some reactor head closure studs installed prior to commercial operation, or used as replacements, may have actual measured yield strength that is greater than 150 ksi. The applicant noted that the GALL Report requires, as a preventive measure to reduce the potential for SCC or IGSCC, using bolting material for the reactor head closure studs that have an actual measured yield strength limited to less than 150 ksi.

The applicant stated that the Byron and Braidwood reactor vessel head closure studs were fabricated from SA-540, Class 3, Grade B23 alloy steel with a specified minimum yield strength of 130 ksi, a minimum tensile strength of 145 ksi, and a maximum tensile strength of 170 ksi. The applicant also stated that material strength of the studs comply with RG 1.65, Revision 0, which was then the current NRC guidance during plant construction. The applicant also stated that the maximum measured yield strength documented for Byron or Braidwood studs is 153 ksi, which is slightly greater than the GALL Report criterion for actual measured yield strength less than 150 ksi.

The applicant further stated that since the actual measured yield strength of the studs may be equal to or greater than 150 ksi, its AMR identified the stud material as "High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater" and identified cracking as an AERM.

The applicant stated that the closure studs are volumetrically (UT) examined during each ISI interval; these examinations are qualified for identifying cracking. The applicant also stated that there have been no recordable indications identified by the volumetric (UT) examination of the closure studs, confirming that the current program is adequate in managing cracking. The applicant further stated that based on the above discussion, the Reactor Head Closure Stud Bolting AMP will be effective in managing for cracking during the period of extended operation. The staff reviewed this exception against the corresponding program element in the GALL Report AMP XI.M3 and finds it acceptable because the applicant's AMR appropriately identified the stud material as susceptible to SCC, and all closure studs are volumetrically inspected by an examination qualified for identifying cracking during each ISI interval.

Enhancement. LRA Section B.2.1.3 includes an enhancement to the "preventive measures" and "corrective actions" elements. The applicant stated that, prior to the period of extended operation, it will revise the procurement requirements for reactor head closure studs material to ensure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP XI.M3 and finds it acceptable because, when implemented, the enhancement makes the program consistent with the GALL Report recommendations for any replacement bolting materials procured during the period of extended operation.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.3-2 and B.2.1.3-3, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M3. The staff also reviewed the exception to the "preventive measures" program element and the justification for the exception; the staff finds that the AMP with the exception is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "preventive measures" and "corrective actions" program elements and finds that, when implemented, the enhancements will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.3 summarizes OE related to the Reactor Head Closure Stud Bolting Program. The applicant stated that ISIs of reactor head closure studs and associated RPV flange threads, nuts, and washers at Byron Units 1 and 2 have resulted in no recordable indications. The applicant also stated that, during the 1999 and 2005 refueling outage (ISI Interval 2, Period 1, Outage 1, and ISI Interval 2, Period 3, Outage 1, respectively), all of the Byron Unit 1 RPV flange threads were inspected using the applicable ASME, Section XI UT methods, with no recordable indications. The applicant further stated that, during these outages all of the nuts and washers were examined using the applicable ASME, Section XI examinations. As of the date of the LRA, inspections performed on its closure bolting in the third ISI interval have not resulted in any recordable indications.

LRA Section B.2.1.3 further states that, during the 2001, 2004, and 2007 refueling outages (ISI Interval 2, Period 1, Outage 2; ISI Interval 2, Period 2, Outage 2; and ISI Interval 3, Period 1, Outage 1, respectively), all of the Byron Unit 2 RPV flange threads and studs were inspected using the applicable ASME, Section XI UT methods, with no recordable indications. In addition, the applicant stated that during the 2004 and 2007 inspections, all the washers and nuts associated with reactor head closure studs were examined using the applicable ASME, Section XI VT methods, with no recordable indications.

LRA Section B.2.1.3 states, for Braidwood Unit 1, ISIs of reactor head closure bolting during the second ISI intervals have not resulted in any recordable indications. The applicant stated that as of the date of the LRA, ISIs performed on its closure bolting in the third interval have not resulted in any recordable indications.

LRA Section B.2.1.3 further states, for Braidwood Unit 2, ISIs of reactor head closure bolting during the second and third ISI intervals have not resulted in any recordable indications. During the 2000, 2002, 2003, and 2007 refueling outages (ISI Interval 2, Period 1, Outage 1; ISI Interval 2, Period 2, Outage 1; ISI Interval 2, Period 2, Outage 2; and ISI Interval 2, Period 3, Outage 1, respectively), all of the reactor head closure studs, flange threads, nuts, and washers were examined using the applicable ASME, Section XI UT and VT methods, with no recordable indications.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff identified OE for which it determined the need for additional information and clarifications and resulted in the issuance of RAIs as discussed below.

During the audit of the "operating experience" program element for Byron Units 1 and 2, the staff found that OE provided by the applicant in the LRA was incomplete. Specifically, the applicant's onsite database contained information related to a stuck reactor vessel closure stud at Byron Unit 2. Based on the information provided by the applicant during the audit, stud No. 11 became stuck during the 2010 outage and did not have enough thread engagement to be tensioned. The applicant then decided to leave the stuck stud in place after cutting approximately 5 in. from the top end of the stuck stud. Therefore, since 2010 the Byron Unit 2 stud No. 11 has been inoperable, and Unit 2 has only 53 of 54 studs operable. In addition, information was not provided in the LRA or during the audit on the root cause of the failure. Without a root cause, the staff is concerned that similar failures could recur and further challenge the integrity of the reactor vessel head.

By letter dated October 7, 2013, the staff issued RAI B.2.1.3-1 requesting that the applicant provide the following. In Part 1 of RAI B.2.1.3-1, the staff requested that the applicant perform a complete plant-specific OE search for Byron Units 1 and 2 and, in addition to stud No. 11, provide search results that include all instances of stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, washers, vessel flange threads, and nuts. In Part 2 of the RAI, the staff requested that the applicant provide a detailed chronology of the events related to Byron Unit 2 stud No. 11. In Part 3 of the RAI, the staff requested the applicant provide a root cause analysis related to the failure of stud No. 11 and to provide information on corrective actions, inspection results, engineering changes, and repair replacement activities related to stud No. 11 and its respective flange hole. In Part 4 of the RAI, the staff requested that the applicant explain in detail the current configuration of stud No. 11 and its flange hole.

By letter dated November 5, 2013, the applicant provided its response to RAI B.2.1.3-1. In its response to Part 1 of the RAI, the applicant stated that it performed a thorough OE review to identify all documented instances of stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, washers, vessel flange threads, and nuts for Byron Units 1 and 2. The applicant stated that the review did not identify any events at Byron Units 1 and 2 caused by age-related degradation, including cracking due to SCC or loss of material due to wear or corrosion. The applicant also stated that its review of OE involved key word searches of the Byron Station Action Request (AR) database, Exelon's Electronic Document Management System regulatory correspondence database, and NRC's Licensee Event Report (LER) database. The applicant further stated that it also reviewed Byron ISI Summary Reports and applicable inspection reports. As part of its response, the applicant provided summaries of the applicable events and conditions (i.e., instances of stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, washers, vessel flange threads, and nuts) that were identified by the OE review.

In its response to Part 2 of the RAI, the applicant stated that, in 1999 prior to the Byron Unit 2 reactor closure head stud No. 11's becoming stuck, Byron Station developed contingency engineering analyses which concluded that Byron Units 1 and 2 could operate with 53 of 54 reactor head closure studs tensioned, and still meet ASME Code Section III allowable stresses requirements. The applicant also stated that, in 2007, all of the Byron Unit 2 reactor closure studs were volumetrically (UT) examined with no recordable indications (stud No. 11 included). The applicant further stated that, during the 2008 refueling outage, stud No. 11 was removed, inspected, lubricated, and reinstalled with no reported problems (stud No. 11 became stuck in 2010).

The applicant stated that a review of the completed 2008 refueling outage reactor disassembly and assembly work orders confirmed that all instructions related to stud No. 11 were followed with no reported problems. The applicant stated that these instructions included:

> procedural requirements for stud detensioning; stud, nut, and washer removal and storage away from reactor cavity borated water; inspection and cleaning of the stud, nut, and washer; plugging and cleaning the associated vessel flange hole; reactor vessel and closure head flange and O-ring inspections; stud and flange hole lubrication; foreign material exclusion; and stud, nut, and washer installation and tensioning. At the conclusion of the 2008 refueling outage, the reactor vessel pressure test was performed, with no observed leakage from the reactor vessel flange.

The applicant stated that in 2010 during reactor disassembly, stud No. 11 became stuck only two turns out of the reactor vessel flange when the Biach electrical stud drive tool stopped rotating the stud. The applicant also stated that an approved lubricant was applied to the stud threads in an effort to loosen the stud while the stud was turned in and out of the reactor vessel flange in quarter-turn increments by manual means. The applicant further stated that when the stud was approximately 4 in. out of the flange stud hole it could no longer be manually turned. The applicant stated that the top 5 in. of the stud were then cut off to provide for easier access during tensioning of the adjacent studs (nos. 12 and 13).

The applicant stated that it performed an engineering evaluation, which allowed for a configuration in which stud No. 11 is not tensioned for power operation. The applicant also stated that vessel pressure tests resulted in no observed leakage from the reactor vessel flange during subsequent outages (no reactor coolant leakage has been observed on the reactor flange since the stud became stuck). The applicant further stated that, during the fall 2011 refueling outage, all reactor flange stud holes, including the one for stud No. 11 were volumetrically (UT) examined with no recordable indications.

In its response to Part 3 of the RAI, the applicant stated that based on its review of all of the available information for Byron Unit 2, the most likely cause for stud No. 11 becoming stuck in 2010 were: "(1) undetected mechanical damage or galled threads during handling or (2) the introduction of undetected foreign material in the flange hole."

The applicant stated that its review did not reveal any evidence that stud No. 11 became stuck due to age-related degradation. The applicant also stated that it came to this conclusion after considering all of the following credible potential causes for a stuck stud: "(a) flange-to-bolt misalignment, (b) foreign material, (c) improper or no thread lubrication, (d) damaged or galled threads, (e) corrosion byproduct buildup on the stud and flange threads, and (f) stud-to-reactor vessel hole cross-threading." As part of its response, the applicant provided a summary of its evaluations relative to each of the referenced factors, (a) through (f), in support of its conclusion.

The applicant stated that a formal root cause evaluation of the 2010 refueling outage event has not been performed. The applicant also stated that a detailed visual inspection of the threads on the stud and associated reactor vessel flange hole would be required to provide important information necessary to determine the root cause, but it is not possible to perform such a detailed inspection, since stud No. 11 cannot be removed from the associated reactor vessel flange hole.

In its response to Part 4 of the RAI, the applicant stated that the current configuration of reactor head closure stud No. 11 and the reactor vessel flange hole are as follows:

> Stud No. 11 is approximately four (4) in. out of the reactor vessel flange hole, which has increased the distance between the bottom of the reactor vessel flange hole and the bottom of the stud by four (4) in.; the stud is stuck in this position and cannot be rotated either in or out of the reactor vessel flange; in addition, the top five (5) in. of the stud have been removed to provide the stud tensioning equipment with easier access to adjacent stud nos. 10 and 12. This has resulted in the height of stud No. 11 being less than 20 in. above the reactor head flange surface.

The staff finds the applicant's response acceptable because the applicant (1) performed a comprehensive review of its OE for Byron Units 1 and 2 reactor vessel closure studs and provided summary descriptions of all instances of stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, washers, vessel flange threads, and nuts; (2) provided a detailed chronology related to stud No. 11's getting stuck; (3) provided its evaluations which provided plausible reasons for stud No. 11's getting stuck, because it is not possible to perform an actual root case analysis without first removing the stud; and (4) provided a detailed description of the current configuration of stud No. 11. The staff's concern described in RAI B.2.1.3-1 is resolved.

By letter dated January 23, 2015, the applicant provided an update on the completion of Commitment No. 47, which states, "Byron Unit 2 reactor head closure stud location 11 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation." The applicant stated that the Byron Unit 2 partially stuck stud No. 11 was removed during the fall 2014 refueling outage. The applicant also stated that a new stud was installed at this location and, therefore, its Commitment No. 47 is completed.

During the audit of the "operating experience" program element for Braidwood Units 1 and 2, the staff found that OE provided by the applicant in the LRA was incomplete. Specifically, the applicant's onsite database contained information related to a stuck reactor vessel closure stud at Braidwood Unit 2. Based on the information provided by the applicant during the audit, stud No. 35 became stuck in 1991. However, the stuck stud had enough thread engagement and was fully tensioned during operations until May of 1994, when the stud was cut at the flange level to facilitate fuel movement activities. In 2002 the applicant initiated repair activities in an effort to restore operability to stud No. 35. The remnant of the stuck stud was bored out. However, during machining operations the flange stud hole for stud No. 35 was overbored due to an error. Further efforts to restore the threads to stud hole no. 35 were suspended; as a result, since 1994 Braidwood Unit 2 has only 53 of 54 studs operable. In addition, information was not provided in the LRA or during the audit on the root cause of why stud No. 35 got stuck, or the failed repair. Without a root cause, the staff is concerned that similar failures could recur and further challenge the integrity of the reactor vessel head.

By letter dated May 19, 2014, the staff issued RAI B.2.1.3-4 requesting that the applicant provide the following. In Part 1 of RAI B.2.1.3-4, the staff requested that the applicant perform a comprehensive plant-specific OE search for Braidwood Units 1 and 2, in addition to stud No. 35, and provide search results that include all instances of stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, guide studs, washers, vessel flange threads, and nuts. In Part 2 of the RAI, the staff requested that the applicant provide a detailed chronology of the events related to Braidwood Unit 2 stud No. 35. In Part 3 of the RAI, the staff requested the applicant provide a root cause analysis related to the failure of stud No. 35. The applicant was also asked to include corrective actions, inspection results, engineering changes, and repair replacement activities related to stud No. 35 and its respective flange hole. In Part 4 of the RAI, the staff requested that the applicant provide details of the current configuration of stud hole no. 35 and provide inspection results from 2002 to present. In Part 5 of the RAI, the staff requested the applicant provide inspection results for stud and stud hole nos. 33, 34, 36, and 37 for Braidwood Unit 2 from 1994 to present.

By letter dated June 9, 2014, the applicant provided its response to RAI B.2.1.3-4. In its response to Part 1 of the RAI, the applicant stated that it performed a thorough OE review as requested, the review involved key word searches of the Braidwood Station Action request database, Exelon’s Electronic Document Management System regulatory correspondence database, and the staff’s LER database. The applicant also stated that it reviewed Braidwood Units 1 and 2 ISI Summary Reports. As part of its response, the applicant provided summary description of events and conditions associated with stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, guide studs, washers, vessel flange threads, and nuts. The applicant’s summaries also included OE related to minor degradation of O-ring mating surfaces.

In its response to Part 2 of the RAI, the applicant stated that in 1991, during the second Braidwood Unit 2 refueling outage, RPV head closure stud No. 35 became stuck during RPV closure head disassembly. The applicant also stated that attempts to remove the stuck stud without using excessive force failed. The applicant further stated that because the stud was only withdrawn 15/32 in. (4 turns) and had sufficient thread engagement to be fully tensioned, it was decided to protect the stud from borated water and leave the stud in place while the reactor cavity was flooded.

The applicant stated that, from the fall of 1991 until the spring of 1994, Braidwood Unit 2 stud No. 35 was fully tensioned during plant operation and was protected from borated water during refueling outages. The applicant further stated that, because the protruding portion of stud No. 35 was an obstacle during refueling outage activities, in the spring of 1994 an evaluation was developed to demonstrate that Braidwood Unit 2 could be placed in service without stud No. 35 tensioned. The applicant stated that an engineering change was performed allowing for a new configuration without stud No. 35, and the portion of the stud that protruded above the flange was removed.

The applicant stated that it developed plans to restore the capability of stud No. 35; the plans included destructively removing the remaining portion of stud No. 35 and a contingency modification in case the flange threads were damaged and could not be reused. The applicant also stated that the contingency modification would require the installation of a larger diameter sleeve in the reactor vessel flange hole, with the outer male threads of the sleeve threading into the new female threads that would be machined into the newly bored and threaded reactor vessel flange hole (a new stud would then be threaded into the inner female threads of the sleeve). The applicant further stated that the plan was implemented and the remaining portion of stud No. 35 was destructively removed from the flange hole; inspection of the flange hole threads revealed significant damage, and it was concluded that the flange hole could not be reused as found.

The applicant stated that it commenced the contingency modification, which first required boring out the damaged threads and then machining new threads for the sleeve. The applicant stated that the vendor's equipment malfunctioned; as a result Braidwood Station decided not to continue with the repair and to continue operating Braidwood Unit 2 with 53 studs tensioned. The applicant also stated that an engineering change was performed to allow for the new configuration of the reactor vessel flange hole in stud location no. 35. The applicant further stated that, in August 2013, a nonconservative input was identified involving Westinghouse WCAP-16143-P, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2," approved in 2003 which justified removing the 10 CFR 50, Appendix G, flange requirements when determining reactor pressure-temperature (P-T) limits. The applicant stated that the technical basis document in this report assumed 54 reactor head closure studs were in service for Braidwood Units 1 and 2; in 2006, the staff approved a license amendment to implement the pressure-temperature limits report (PTLR), using the methodology of WCAP-16143-P as one of the basis documents for the current PTLR reports for BBS Units 1 and 2. The applicant stated that, given that the P-T limits minimum temperature requirement, methodology in WCAP-16143-P was not based on the configuration of the closure flange assemblies at Braidwood Unit 2; the issue was entered into the CAP. The staff's review of the applicant's TLAA on P-T limits and its proposed disposition of the TLAA are discussed in SER Section 4.2.5.2.

The applicant further stated that, in October 2013, a nonconservative input related to the original calculation that justified operating Braidwood Unit 2 with 53 reactor vessel closure studs tensioned was identified and entered into the CAP. The applicant stated that the calculation incorrectly used a larger washer bearing surface area between the closure stud washers and the reactor vessel head. The applicant stated that it performed an operability evaluation, based on the material's measured mechanical properties, which determined that the stresses were below the ASME allowable limit.

In its response to Part 3 of the RAI, the applicant stated that, based on the review, the likely potential reason for stud No. 35's becoming stuck in 1991 were caused by: "(1) undetected mechanical damage or galled threads during handling, (2) undetected improper thread lubrication during installation of the stud during the previous refueling outage, or (3) the introduction of undetected foreign material in the flange hole."

The applicant stated that its review did not reveal any evidence of age-related degradation that caused stud No. 35 became stuck. The applicant also stated that it came to the above conclusion after considering all of the following credible potential causes for a stuck stud: "(a) flange-to-bolt misalignment, (b) foreign material, (c) improper or no thread lubrication, (d) damaged or galled threads, (e) corrosion byproduct buildup on the stud and flange threads, and (f) stud-to-reactor vessel hole cross-threading." As part of its response, the applicant provided a summary of its evaluations relative to each of the referenced factors, (a) through (f), in support of its conclusion.

The applicant stated that a formal root cause evaluation of the 1991 refueling outage event has not been performed. The applicant also stated that visual examination of the threads would have provided important information necessary to determine a root cause. The applicant further stated that, because the stud was destructively removed in 2002, and the threads were damaged in the removal process, it was not possible to perform such an inspection. As part of its response, the applicant provided a chronological summary of all of the repair replacement activities related to stud No. 35.

In its response to Part 4 of the RAI, the applicant stated that the original diameter of the stud hole was approximately 7 in. The applicant stated that during the 2002 contingency modification of the flange hole associated with Braidwood Unit 2 stud No. 35, the diameter of the flange hole was enlarged to 7.610 to 7.615 in., along its full depth. The applicant also stated the top 1.45 in. of the stud hole was enlarged to an approximately 8.368 in. diameter to accommodate the top unthreaded portion of the insert. The applicant stated that the depth of the flange hole is approximately 14.313 in. The applicant further stated that the threads for the flange hole were not machined and the flange hole for stud No. 35 is currently in the above described as-machined configuration.

As part of its response, the applicant stated that, during the fall 1997 refueling outage, all reactor vessel flange stud holes were volumetrically examined with no recordable indications (including the flange hole for stud No. 35). The applicant also stated that, during the fall 2000 refueling outage, all reactor vessel flange stud holes were again volumetrically examined, including the flange hole for stud No. 35, with no recordable indications. The applicant further stated that, during the spring 2002 refueling outage, after the diameter of the reactor vessel flange hole associated with stud No. 35 was enlarged, the flange hole was volumetrically examined to ensure the flange ligaments in the vicinity of the stud hole were not damaged, and this inspection did not result in any recordable indication. The applicant stated that the reactor vessel flange hole for stud No. 35 is cleaned and inspected prior to reactor vessel floodup, and the stud hole is cleaned and inspected, and borated water is removed after the reactor cavity is drained.

In its response to Part 5 of the RAI, the applicant stated that, during the fall 1997 refueling outage, the closure studs and flange stud holes associated with studs 33, 34, 36, and 37 were examined, with no recordable indications. The applicant also stated that, during the fall 2000 refueling outage, the flange stud holes 33, 34, 36, and 37 were examined with no recordable indications. The applicant further stated that, during the fall 2003 refueling outage, reactor vessel closure studs 33, 34, 36, and 37 were examined, with no recordable indication. The applicant further stated that, during the spring 2014 refueling outage, closure studs 33, 34, 36 and 37 were volumetrically examined with no recordable indications.

The staff finds the applicant's response acceptable because the applicant (1) performed a thorough review of its OE for Braidwood Units 1 and 2 reactor vessel closure studs and provided summary descriptions of all instances of stuck studs, missing threads, damaged threads, or any form of degradation in RPV studs, washers, vessel flange threads, and nuts; (2) provided a detailed chronology of the events related to stud No. 35; (3) provided evaluations that demonstrated plausible reasons for stud No. 35's getting stuck (the evaluations were required because it was not possible to perform a root cause analysis since the stud was destructively removed and the flange threads were damaged during the removal process); (4) provided a detailed description of the current configuration of the stud hole for stud No. 35 as well as satisfactory inspection results of the stud hole for stud No. 35; and (5) provided satisfactory inspection results from 1997, 2000, 2003, and 2014 for studs and stud holes 33, 34, 36, and 37. The staff's concern described in RAI B.2.1.3-4 is resolved.

Based on its audit and its review of the application, review of the applicant's responses to RAIs B.2.1.3-1 and B.2.1.3-4, and review of the applicant's commitments, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that with the implementation of the applicant's commitments, the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M3, was evaluated.

UFSAR Supplement. LRA Section B.2.1.3, as revised by letters dated November 5, 2013, and December 19, 2013, provides the UFSAR supplement for the Reactor Head Closure Stud Bolting Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.0-1.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Reactor Head Closure Stud Bolting Program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancement and exception and their justifications and determines that the AMP, with the exception and enhancement, is adequate to manage the applicable aging effects. Also, the staff reviewed the applicant's Commitment No. 48 and confirmed that its implementation as proposed in the license condition prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 PWR Vessel Internals

Summary of Technical Information in the Application. LRA Section B.2.1.7 describes the new PWR Vessel Internals Program as consistent, with an exception with GALL Report AMP XI.M16A, "PWR Vessel Internals."

The LRA states that the PWR Vessel Internals Program is a condition monitoring program designed to manage the effects of age-related degradation for aging effects that are applicable to PWR reactor vessel internal (RVI) components in a reactor coolant with neutron flux environment. The LRA further states that these aging effects include: (a) various forms of cracking, including SCC, PWSCC, irradiation-assisted stress-corrosion cracking (IASCC), and cracking due to fatigue/cyclical loading; (b) loss of material induced by wear; (c) loss of fracture toughness due to neutron irradiation embrittlement; (d) changes in dimension due to void swelling and irradiation growth; and (e) loss of preload due to thermal and irradiation enhanced stress relaxation or creep.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 9 of the applicant's program to the corresponding program elements of GALL Report AMP XI.16A, as revised and updated in License Renewal Interim Staff Guidance (LR-ISG)-2011-04, which was issued on May 28, 2013 (ADAMS Accession No. ML12270A436).

The staff noticed that, in the LRA, the applicant identified the LR-ISG-2011-04 based version of the PWR Vessel Internals Program as an exception to the version of the GALL AMP XI.M16A. The staff reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls" 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 also reviewed the applicant's response bases to the staff's applicant/licensee action items (A/LAIs) that were issued in MRP-227-A. The staff's evaluations of the applicant's exception to GALL AMP XI.M16A and of the applicant's responses to the A/LAIs on the MRP-227-A methodology are documented in the following subsections.

Exception. LRA Section B.2.1.7 includes an exception to the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls" program elements. The applicant stated that the GALL Report (i.e., NUREG-1801, Revision 2) describes an AMP for the PWR RVI components in Section XI: XI.M16A, "PWR Vessel Internals." The applicant stated that the exception for this AMP is that the "PWR Vessel Internals" AMP is consistent with NUREG-1801 as modified by the changes to GALL AMP XI.M16A in the March 20, 2012, draft of LR-ISG-2011-04.

The staff noticed that during the development of the LRA, Draft LR-ISG-2011-04 was the most up to date guidance available for aging management of PWR internals. The final version of LR-ISG-2011-04 was issued by letter dated May 28, 2013, and the revisions in the final version were to clarify and simplify the guidance documented in Draft LR-ISG-2011-04. The applicant submitted its LRA by letter dated May 29, 2013, after the issuance of the final version of LR-ISG-2011-04. The staff noticed that the technical content and recommendations for aging management were not altered between the draft and final versions. Thus, the staff's review of the applicant's PWR Vessel Internals program was based on Final LR-ISG-2011-04.

The staff reviewed this exception and finds that the applicant used the most up to date guidance available on aging management of PWR internals to develop its LRA. Also, the staff subsequently reviewed the applicant's PWR Vessel Internals program in accordance with the final version of LR-ISG-2011-04; the staff find this exception is no long applicable.

Review of License Renewal Applicant/Licensee Action Items. In the staff's safety evaluation, Revision 1, (ADAMS Accession No. ML11308A770) for the topical report, MRP-227-A, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," the staff issued the following license renewal applicant action items in the report:

(1) Applicability of failure modes, effects, and criticality assessment (FMECA) and Functionality Analysis Assumptions

(2) PWR Vessel Internal Components Within the Scope of License Renewal

(3) Evaluation of the Adequacy of Plant-Specific Existing Programs

(4) Babcock & Wilcox (B&W) Core Support Structure Upper Flange Stress Relief

(5) Application of Physical Measurements as part of inspection and evaluation (I&E) Guidelines for B&W, Combustion Engineering (CE), and Westinghouse RVI Components

(6) Evaluation of Inaccessible B&W Components

(7) Plant-Specific Evaluation of CASS Materials

(8) Submittal of Information for Staff Review and Approval (five subparts)

1. The staff reviewed the applicant's response to A/LAI No. 1, as documented in LRA Appendix C, which states the applicant has assessed its plant design and operating history and has determined that MRP-227-A is applicable to the facility. The staff noticed that the assessment performed by the applicant addressed the broad set of assumptions about plant operation, which encompass the range of current plant conditions for the U.S. domestic fleet of PWRs, the functionality assessments and supporting aging management strategies performed by the MRP, and the representative configurations and operational histories, which were generally conservative but not necessarily bounding in every parameter.

Since a number of industry licensees were establishing their efforts to resolve the staff's actions requested in A/LAI No. 1, the staff held a series of proprietary and public meetings with members of Westinghouse, the EPRI MRP, and NRC-licensed utilities in order to: (a) address the staff's regulatory bases for resolving this action item, (b) encourage the development of a generic approach that could be used to resolve the requests in A/LAI No. 1, and (c) establish a path for receiving comprehensive and consistent utility responses that would address the applicability of the MRP-227-A methodology for PWRs having either Westinghouse or CE RVI designs. As a result of these discussions, the staff agreed that a generic approach could be applied as a basis for resolving the action requests in A/LAI No. 1 if an applicant addressing the action item would respond to the following questions that relate to the unit's reactor design:

> Question 1: Does the plant have any non-welded or bolted austenitic stainless steel (SS) components with 20 percent cold work or greater; and, if so, do the affected components have operating stresses greater than 30 ksi? (If both conditions are true, additional components may need to be screened in for stress corrosion cracking, SCC.)
>
> Question 2: Does the plant have atypical fuel design or fuel management that could render the assumptions of MRP-227-A, regarding core loading/core design, non-representative for that plant?

By a letter dated October 14, 2013, the EPRI MRP issued EPRI MRP Letter 2013-025, "MRP-227-A Applicability Guidelines for Combustion Engineering and Westinghouse Pressurized Water Reactor Designs" (ML13322A454), which provided the industry licensees with a non-proprietary, generic methodology for responding to the two questions on A/LAI No. 1. The staff noticed that, in regard to resolving the request in Question 1, the EPRI MRP letter provides the licensees with guidance for assessing whether the RVI components at their plant, other than those identified in the generic evaluation, would have the potential for cold work greater than 20 percent, and if so, whether the operating stresses for those components would be in excess of 30 ksi. Under this basis, non-welded or bolted RVI components that have cold-work and stress levels in excess of these criteria would need to be considered for augmented inspections or evaluations under the MRP's recommended protocols in EPRI MRP Letter No. 2013-025.

With respect to resolving Question 2, the staff noticed that EPRI MRP Letter 2013-025 provided specific quantitative criteria that would allow a licensee to assess whether a particular plant has atypical fuel design or fuel management. For the Westinghouse-design plants at BBS, the threshold criteria for assessing fuel load assumptions in EPRI MRP Letter No. 2013-025 used to demonstrate conformance with the fuel loading assumptions in the MRP-227-A report are:

(1) The heat generation rate must be ≤ 68 watts/cm^3.
(2) The maximum average core power density must be < 124 watts/cm^3.
(3) The distance from the top of the active fuel to upper core plate must be > 12.2 in.

By letter dated March 20, 2014, the staff issued RAI B.2.1.7-7, Part 1, which requested that the applicant clarify if its plant has non-welded or austenitic SS components with 20 percent or greater cold work, and if so, whether the affected components have operating stresses greater than 30 ksi. In addition, Part 2 of RAI B.2.1.7-7 asked the applicant to clarify if its fuel design and fuel management are bounded by the assumptions of MRP-227-A and MRP-191 that were used to assess the core loading patterns and core designs of Westinghouse-designed RVI components.

By letter dated April 14, 2014, the applicant responded to RAI B.2.1.7-7. The applicant stated it contracted its RVI supplier to perform a detailed review of the BBS RVI fabrication records to identify any non-welded or bolted SS components that may have been cold worked greater than 20 percent and are subject to operating stresses greater than 30 ksi. The applicant stated that this detailed review will be completed and the results communicated to the staff. By letter dated September 4, 2014, the applicant submitted a supplemental response to RAI B.2.1.7-7 containing the results of the review. In its response, the applicant stated that it used the generic criteria in EPRI Letter No. MRP 2013-025 as the basis for assessing whether the assumptions in MRP-227-A were bounding for the design and operations of the RVIs at Units 1 and 2. The applicant confirmed that all components applicable for its design were directly included in the component list in the MRP-191 report.

Regarding the question on whether the plant design included reactor vessel components with cold work levels in excess of 20 percent and operating stresses in excess of 30 ksi, the applicant stated that, when a component had a potential to be cold worked, for the purposes of this assessment, it assumed the component to be cold worked. The applicant also stated that when the historical record was not detailed enough to preclude cold work, it used a conservative approach and assumed that the component was cold worked. The applicant further stated that its evaluation determined that all of the RVI components with a potential for cold work had already been assumed to have been cold worked in the MRP-191 report generic assessment and are within the appropriate augmented inspection protocols of the MRP-227-A report. Based on this evaluation, the applicant concluded that the cold work and stress assumptions used to develop the MRP's sampling based inspection methodology in MRP-227-A remained bounding and valid for the design of the RVIs at BBS.

In its review of the applicant's response, the staff notes that the applicant used the available fabrication records and a conservative approach in determining the possibility of cold work. The staff also confirmed that, for those RVI components assumed to be cold worked, the components are already within the augmented inspection bases of the MRP-227-A. Therefore, the staff finds the applicant's response as it relates to its screening for RVI components for cold work acceptable because the applicant demonstrated that its plant-specific internals components were consistent with the generic assumptions for MRP-227-A, as well as MRP-191 basis report. The staff's concern in RAI B.2.1.7-7, Part 1 is resolved.

In its response to RAI B.2.1.7-7, Part 2, the applicant stated that the BBS fuel design and fuel loading were evaluated against the criteria in EPRI letter MRP 2013-025, "MRP-227-A Applicability Template Guideline," Attachment 1, to determine if the units used atypical fuel designs or fuel management that could render the assumptions of MRP-227-A, regarding loading and core design, non-representative for the design of the RVI components in the Byron and Braidwood units. The applicant stated that MRP 2013-025 explored three boundaries to develop its criteria: radial boundary evaluation, upper axial boundary criteria, and lower axial boundary criteria.

For the radial boundary evaluation, the applicant stated that fuel loading of the reactor units at BBS uses an in-out fuel loading pattern. In its response, the applicant provided tables of its average core power densities and the cycles that exceeded the figure of merit. The applicant stated that the average core power density for all past BBS, Units 1 and 2, operating cycles was less than the criteria of 124 watts/cm^3. The applicant stated that, with regard to the heat generation figure of merit, all reload fuel cycles met the limit of less than or equal to 68 watts/cm^3, with the exception of five reload fuel cycles for the four units. The applicant stated that the time the heat generation figure of merit exceeded the criteria was less than 2 effective full-power years (EFPY) and requires no further evaluation for Byron, Units 1 and 2, and Braidwood, Unit 2. For Braidwood, Unit 1, the applicant stated that the total time was 2.29 EFPY. The applicant stated that this short duration that exceeded the limit, 0.29 EFPY, is offset by the many years of operation where the heat generator figure of merit was below the limit. The staff noticed that these five cycles that exceeded the limit occurred within the first 20 years of operation for the respective unit.

For the upper axial evaluation, the applicant stated that standard 17x17 Westinghouse fuel product line fuel assemblies were used throughout the associated operating histories at BBS, Units 1 and 2. The applicant stated that it reviewed its standard fuel product line fuel assembly designs to determine that the limit of greater than 12.2 in. for the distance from the active fuel to the upper core plate was met. The applicant stated that eight lead use assemblies were used during Braidwood Unit 1, Cycles 15 and 16. The applicant stated that the distance between the active fuel and core plate for these assemblies was greater than 12.2 in. The applicant also stated that the average core power density for all past BBS, Units 1 and 2, operating cycles was less than the limit of 124 watts/cm^3.

The applicant also stated that the core design process will be modified to include a review of the following parameters: (1) active fuel – upper core plate distance greater than 12.2 in., (2) average core power density less than 124 watts/cm^3, and (3) heat generation figure of merit less than or equal to 68 watts/cm^3.

Based on this review, the staff finds that the applicant has provided adequate demonstration that the fuel loading patterns assumed in MRP-227-A will be representative of plant operations at BBS, Units 1 and 2, because (a) for all three parameters (with the exception of the heat generation figure of merit for Cycles 1 and 3 of Braidwood Unit 1 and for Cycles 1 of Braidwood Unit 2 and Byron Units 1 and 2), the applicant demonstrated that the core loading parameters are within the thresholds set for these parameters in the EPRI MRP Letter No. MRP-2013-25, (b) this demonstrates that the core loading patterns for the reactor unit are bounded by the fuel loading assumptions for Westinghouse-designed internals in the MRP-227-A report, and (c) the applicant amended its core operating procedures to perform reviews of the average core density, heat generation figure of merit, and active fuel upper core plate distance parameters during the period of extended operation. The staff's concern in RAI B.2.1.7-7, Part 2, is resolved; and therefore, A/LAI No. 1 is resolved.

2. The staff reviewed the applicant's response to A/LAI No. 2, as documented in LRA Appendix C, which states that MRP-189 and Table 4-5 of MRP-191 are not applicable to its site. In addition, the applicant states that all of the components determined to be within the scope of license renewal are listed in MRP-191, Table 4-4, however two components were made of a different grade of austenitic SS than specified in MRP-191. The applicant stated that these differences did not impact the recommendations in MRP-227-A.

The applicant states that the two components in the upper internals assembly were identified as being fabricated from CASS rather than forged 304 SS as specified in MRP-191, Table 4-4. The first component that the applicant identified was the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps for BBS. The applicant stated that, due to the material difference in these components, an FMECA was performed, which determined that, with the inclusion of loss of fracture toughness due to thermal aging embrittlement as a degradation mechanism, the components remained in the "No Additional Measures" inspection category. However, the staff noticed that the details and basis for the applicant's FMECA conclusion were not provided for the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps. The staff noticed that this information is necessary to assess whether the applicant will implement an adequate aging management strategy for these components. The staff also noticed that the applicant's response to A/LAI No. 2 focused on how thermal embrittlement was assessed in the FMECA process, but did not provide a discussion on how irradiation embrittlement was considered. It is not clear to the staff if or how irradiation embrittlement was considered in the applicant's FMECA for the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps installed at BBS. By letter dated December 12, 2013, the staff issued RAI B.2.1.7-1, which requested the applicant to describe in detail the FMECA performed for these components when considering loss of fracture toughness due to thermal and irradiation embrittlement and to justify the conclusion that components were ranked as Category A components, which equate to "No Additional Measures" inspection category.

In its response, by letter dated January 13, 2014, the applicant stated that, consistent with the basis in MRP-191, an FMECA was performed and an expert panel was assembled and charged to evaluate the potential effects of the material variance on the MRP-191 industry generic susceptibility ranking of these components. The applicant stated the expert panel evaluated the impact the use of CASS would have on the function of the component, potential degradation mechanisms, likelihood of failure, and likelihood of damage. The applicant further stated that the expert panel concluded that the use of CASS in the design of the RVI upper instrumentation conduit and supports, brackets, clamps, terminal blocks, and conduit straps did not impact the function of the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps. The staff finds this conclusion to be valid because a change in the material of construction for the components would not impact the design functions of the components.

To address irradiation embrittlement for these components, the applicant stated that, since the components are located above the active core in a low fluence region, the fluence is below the MRP-191 screening threshold for inducing irradiation embrittlement in the components. The staff finds this basis to be acceptable because: (a) the RVI upper instrumentation conduit and supports, brackets, clamps, terminal blocks, and conduit straps are located above the active reactor core in the vessels, and (b) based on their component locations, the projected accumulated fluence will be less than the threshold criterion for inducing irradiation embrittlement in CASS RVI components, as established in MRP-191.

To address thermal aging embrittlement, the applicant stated that the expert panel determined that the failure of the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps with the consideration of thermal aging embrittlement was "Low" categorization, consistent with the generic MRP-191, Table 6-2 ranking criteria. The applicant further stated that the likelihood of damage resulting from a failure of the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps was determined to be "Low" categorization by the expert panel, consistent with the generic MRP-191, Table 6-3 ranking criteria. The applicant stated that the failure of the component may impact the reliability of the core exit thermocouple(s), but failure or deviations of the thermocouple signal would be detected during normal plant operation. The applicant further stated that the primary concern with failure was identified as a loose part. Based on plants' flow paths, the applicant stated that the loose part would travel to the steam generator, where it would likely be detected. The applicant stated that no safety impact was identified, and the other potential impact would be financial. The applicant also stated that the expert panel evaluation assessed and assigned the FMECA as Group 1. The applicant stated that, based on these results, the expert panel concluded that there was no impact on and no change required to the current aging management strategy for the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps as a result of the material variance from the MRP-191 evaluation. The applicant further stated that the components were assigned to MRP-191 Category A, which equates to the "No Additional Measures" inspection category. The staff finds this acceptable because the applicant confirmed that its FMECA was performed consistent with the guidance and requirements of MRP 191-Section 6 and provided an adequate basis to determine that the material difference of the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps would not impact the categorization as "No Additional Measures" components. The staff's concern in RAI B.2.1.7-1 is resolved.

The second component that the applicant identified was the upper support plate assembly: upper support plate, flange, and upper support ring or skirt at the Byron site only. The applicant stated that, due to the material difference in these components, an FMECA was performed, which determined that the upper support plate was "Non-Category A"; thus, further evaluation is required for plant-specific disposition. The applicant explained in its response to A/LAI No. 2 that based on the certified material test reports (CMTRs) and use of guidance in NRC letter dated May 19, 2000, "License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," the single piece castings, which includes the upper support plate, at Byron Station Units 1 and 2, are not susceptible to loss of fracture toughness due to thermal aging embrittlement. As a result, the applicant determined that the upper support plate was categorized as a "No Additional Measures" component consistent with its original categorization in MRP-227-A.

However, the staff noticed that the details and bases for the applicant's FMECA and susceptibility analysis conclusion for thermal aging embrittlement were not provided for the upper support plate assembly, which is necessary to assess whether the applicant will implement an adequate aging management strategy. The staff also noticed that the applicant's response to A/LAI No. 2 focused on how thermal aging embrittlement was assessed in the FMECA process, but did not provide a discussion on how irradiation embrittlement was considered. It is not clear to the staff if or how irradiation embrittlement was considered in the applicant's FMECA for the upper support plate assembly: upper support plate, flange, and upper support ring or skirt installed in Byron Station Units 1 and 2.

By letter dated December 12, 2013, the staff issued RAI B.2.1.7-2, which requested the applicant to describe and justify how loss of fracture toughness due to irradiation embrittlement was considered in the FMECA. The staff also requested the applicant to describe and justify the susceptibility evaluation performed for the upper support plate that utilized the CMTRs and guidance in the NRC letter dated May 19, 2000, to determine that the single piece castings for the Upper Support Plate Assembly are not susceptible to thermal aging embrittlement.

In its response, by letter dated January 13, 2014, the applicant stated that the FMECA of Byron Station, Units 1 and 2, upper support plate assembly: upper support plate, flange, and upper support ring or skirt considered the loss of fracture toughness due to irradiation embrittlement. Based on the component location and projected neutron fluence, the applicant determined the threshold for the inclusion of loss fracture toughness due to irradiation embrittlement was not met. The applicant stated that the cast upper support plate is located in the reactor vessel flange and reactor vessel head region of the reactor vessel and that the projected 60-year fluence of components in this region of the reactor vessel is less than 1×10^{17} n/cm^2 (E>1.0 MeV). The staff noticed that the MRP-191 established screening criteria for irradiation embrittlement in CASS is less than 6.7×10^{20} n/cm^2 (E>1.0 MeV). The staff finds it acceptable that irradiation embrittlement is not an applicable aging mechanism for the components because the accumulated fluence is less than the threshold criterion for irradiation embrittlement established in MRP-191.

The applicant also stated that the loss of fracture toughness due to thermal embrittlement susceptibility evaluations for the Byron Station, Units 1 and 2, upper support plates were performed using the recommended guidance in NRC letter dated May 19, 2000. The applicant stated that the upper support plates were fabricated from American Society for Testing and Materials (ASTM) A351 Grade CF9 CASS and were conservatively assumed to have been static cast. The applicant stated that the calculated delta ferrite content was determined using the CMTR data. The applicant stated that the delta ferrite content of the upper support plates were calculated to be less than or equal to 20 percent, which screened the components as not susceptible to loss of fracture toughness due to thermal aging embrittlement. The staff finds it acceptable that the Byron Station, Units 1 and 2, upper support plates are not susceptible to thermal aging embrittlement because it was screened out using a methodology established by the staff in its letter dated May 19, 2000. The staff's concern in RAI B.2.1.7-2 is resolved.

The staff noticed that the purpose of A/LAI No. 2 was to (a) verify that the applicant has reviewed the information in Tables 4-1 and 4-2 in MRP 189, Revision 1, and Tables 4-4 and 4-5 in MRP-191 and identify whether these tables contain all of the RVI components that are within the scope of license renewal for its facility and (b) if the tables do not identify all the RVI components that are within the scope of license renewal, the applicant shall identify the missing component(s) and propose any modifications to the program as defined in MRP-227-A. The staff finds that the applicant has adequately addressed A/LAI No. 2 because the applicant identified its plant-specific components outside of those included in MRP-189 and MRP-191 and provided sufficient demonstration that the EPRI MRP's protocols for inspecting the components do not need to be altered or augmented beyond those recommended for the components in MRP-227-A. A/LAI No. 2 is resolved.

3. The staff reviewed the applicant's response to A/LAI No. 3, as documented in LRA Appendix C, which states the original equipment alloy X-750 control rod guide tube (CRGT) split

pins were proactively replaced at BBS with cold worked 316 SS split pins based on industry guidance. The applicant also stated that currently there is no vendor specific requirement to inspect the replacement CRGT split pins; however, through the station's participation in industry groups and the evaluation of industry OE, this position may change as warranted.

The staff noticed that Section 3.5.2.3 of the SE, Revision 1 for MRP-227 states, in part, that it is recommended that the evaluation performed by the applicant in response to A/LAI No. 3 "consider the need to replace the Alloy X-750 support pins (split pins), if applicable, or inspect the replacement Type 316 SS support pins (split pins) to ensure that cracking has been mitigated and that aging degradation is adequately monitored during the extended period of operation." The staff noticed that the applicant has already replaced all of its X-750 split pins at BBS and is not proposing to inspect the replacement Type 316 SS support pins (split pins) during the period of extended operation. It was not clear to the staff why cracking was not an aging effect that would need to be managed in the replacement CRGT split pins that were made from Type 316 SS materials or why the applicant would not need to inspection these pins as part of an adjustment of the program, as recommended in A/LAI No. 2.

By letter April 10, 2014, the staff issued RAI B.2.1.7-3 requesting that the applicant describe in detail (e.g., inspection scope, frequency, technique, etc.) and justify how it will be ensured by the applicant that cracking has been mitigated for the replacement Type 316 SS support pins (split pins) and that age-related degradation is adequately monitored during the period of extended operation. Otherwise, provide the basis that the Section 3.5.2.3 of the SE, Revision 1 for MRP-227 and A/LAI No. 3 are adequately addressed in the LRA and that age-related degradation is adequately monitored during the period of extended operation.

In its response, by letter dated May 12, 2014, the applicant stated that specific inspection of the cold-worked Type 316 split pins for cracking is not necessary. The applicant stated that the replacement split pins were qualified for a 40 year life. The applicant stated that the replacement split pins were evaluated for long term material-related effects which include IASCC, PWSCC, irradiation swelling and densification, embrittlement, and toughness. The applicant also stated that the maximum yield strength of the CRGT split pins was maintained below the limit described in NRC RG 1.85, "Materials Code Case Acceptability ASME Code Section III Division 1," Revision 30, to prevent concerns with SCC. The staff noticed that the evaluation associated with design changes governing the replacement CRGT split pins conserved the effects of age-related degradation and qualified the design for 40-years from the time of installation, which, based on the time of installation, extends beyond the period of extended operation.

The applicant further stated its ASME Section XI Inservice Inspection Program includes the upper internals assembly, which is classified as an ASME Section XI, Examination Category B-N-3 core support component. The applicant stated that, although the CRGT split pins are not specifically listed in the examination scope of the upper internals assembly, the upper core plate, CRGT, and locking devices are listed within the scope. The applicant stated that the visual inspection of the accessible portions of the exterior CRGT split pins is inherent in the VT-3 examination of the upper core plate, CRGT, and locking devices accessible surfaces. The applicant further stated that, in addition to the ASME Section XI Inservice Inspection Program B-N-3 examination, a foreign material inspection of the reactor vessel is performed every refueling outage prior to full core reload. The applicant stated that fragments of the CRGT support pin failures would be detected during visual inspection of the steam generators' primary channel heads. The applicant revised its response to A/LAI No. 3 in LRA Appendix C, to state that it will use its foreign material inspection and the ASME Section XI Inservice Inspection

Program B-N-3 examination of the upper internals assembly to monitor the integrity of the CRGT split pins during the period of extended operation.

The staff finds that, in a way consistent with MRP-227-A, the applicant is following the supplier recommendations (i.e., evaluations associated with the design change governing the replacement CRGT split pins). In addition, the staff finds that the inspection of the upper internals assembly, in accordance with ASME Code Section XI, Examination Category B-N-3, and its foreign materials inspection will identify age-related degradation during the period of extended operation. Thus, the staff finds the applicant's response acceptable. The staff's concerns in RAI B.2.1.7-3 are resolved.

The staff determined that the purpose of A/LAI No. 3 was to justify the acceptability of the applicant's existing program or to identify changes to the programs that should be implemented to manage the aging of these components for the period of extended operation. The staff finds that the applicant has adequately addressed A/LAI No. 3 because: (1) the applicant performed an evaluation that assessed the Type 316 split pins for the effects of age-related degradation and that qualified the design of the split pins for 40-years from the time of installation, which extends beyond the period of extended operation; and (2) the applicant will continue to perform VT-3 inspections in accordance with ASME Code Section XI, Examination Category B-N-3, and foreign materials inspections to confirm that age-related degradation is not occurring in the CRGT supports pins. A/LAI No. 3 is resolved.

4. The staff reviewed the applicant's response to A/LAI No. 4, as documented in LRA Appendix C, which states this item is not applicable to BBS and there are no actions for Westinghouse internals identified in this action item, only for B&W internals.

The staff determined that A/LAI No. 4 of MRP-227-A is associated with confirming that the core support structure upper flange welds in B&W reactors were stress relieved during the original fabrication of the reactor units. The staff noticed that the A/LAI No. 1 is only associated with the design of RVI components in B&W-designed reactors and the UFSAR Section 1.1 verifies that the nuclear steam supply system (NSSS) components (including the RVI components) were fabricated by the Westinghouse Electric Company.

The staff finds that the applicant has made a valid statement that A/LAI No. 4 is not applicable to the BBS CLB because the A/LAI is only applicable to B&W-designed reactors, and the staff has confirmed that the A/LAI is not applicable to the design of the RVI components at BBS, which were designed by the Westinghouse Electric Company. A/LAI No. 4 is resolved.

5. The staff reviewed the applicant's response to A/LAI No. 5, as documented in LRA Appendix C, which states its sites are Westinghouse designed plants and use hold down springs fabricated from Type 403 SS. The LRA states that the requirement to perform physical measurements of the hold down spring specified in MRP-227-A, Table 5-3 is only applicable to hold down springs made from 304 SS; therefore, this item is not applicable. The LRA states that the hold down springs fabricated from Type 403 SS are classified as "No Additional Measures" per MRP-191, Table 6-5.

The staff determined that stress relaxation is the unloading of preloaded components due to long-term exposure to elevated temperatures (i.e., loss of preload is a thermally activated process). Thus, the staff finds it reasonable that at PWR operating temperatures, which are less than 400□°C, the stress relaxation of Type 403 SS would also be lower than the stress relaxation of Type 304 SS. The staff also determined that stress relaxation in springs fabricated from Type 403 SS is not as likely to occur when compared to springs fabricated from Type 304 SS because of the higher yield stress in Type 403 SS, which imparts improved resistance to loss of preload, may result from stress relaxation or irradiation assisted creep aging mechanisms. The staff confirmed that MRP-191, a basis document for MRP-227-A, evaluated Type 403 hold down springs and classified them as “No Additional Measures” components.

The staff finds that the applicant has adequately addressed A/LAI No. 5 because the applicant demonstrated and the staff has confirmed that the hold down springs at BBS are not fabricated from Type 304 SS and because the applicant demonstrated that corresponding physical measurements do not need to be performed on the Type 403 martensitic SS hold-down spring. A/LAI No. 5 is resolved.

6. The staff reviewed the applicant’s response to A/LAI No. 6, as documented in LRA Appendix C, which states this item is not applicable and there are no actions for Westinghouse internals identified in this action item, only for B&W internals.

The staff confirmed that A/LAI No. 6 of MRP-227-A is associated with justifying the acceptability for continued operation through the period of extended operation by evaluation or scheduled replacement of the inaccessible B&W core barrel cylinders (including vertical and circumferential seam welds), B&W former plates, B&W external baffle-to baffle bolts and their locking devices, B&W core barrel-to-former bolts and their locking devices, and B&W core barrel assembly internal baffle-to-baffle bolts.

The staff finds it appropriate that the applicant, a Westinghouse designed plant, did not address A/LAI No. 6 because the components associated with this action item are for B&W plants. A/LAI No. 6 is resolved.

7. The staff reviewed the applicant’s response to A/LAI No. 7, as documented in LRA Appendix C, which states the lower support assembly: lower support column bodies are fabricated from forged Type 304 SS; therefore, no site-specific analysis is necessary for the lower support column bodies. The staff noticed that for Westinghouse-designed internals, A/LAI No. 7 specifically addresses Westinghouse lower support column bodies and any additional martensitic, precipitation hardened, or CASS RVI components that were not addressed and dispositioned in the development of MRP-227-A. For components within the scope of this A/LAI, the staff recommended that the applicant demonstrate adequate management of loss of fracture toughness/thermal aging and neutron irradiation embrittlement in the components through submittal of a component-specific evaluation to the staff for approval; the A/LAI identifies that applicable evaluation may be accomplished through performance of either a component-specific flaw tolerance, susceptibility, or functionality analysis.

Since the applicant’s lower support column bodies are not made from CASS materials, which the staff confirmed in the applicant’s UFSAR, the staff finds it acceptable that the applicant is not required to perform a susceptibility, functionality or flaw tolerance evaluation for its lower support column bodies in response to A/LAI No. 7. However, the staff noticed that the applicant identified some additional components that may be fabricated from martensitic, precipitation hardened, or CASS that were not evaluated in the development of MRP-227-A. As discussed in A/LAI No. 2, the upper instrumentation conduit and supports: brackets, clamps, terminal blocks, and conduit straps at BBS and the upper support plate assembly: upper support plate, flange, and supper support ring or skirt at Byron, Units 1 and 2, were fabricated from CASS. The applicant stated that these components were determined to not be susceptible to a loss of fracture toughness due to thermal and irradiation embrittlement, which the staff finds acceptable as discussed in the staff's evaluation of the applicant's response to A/LAI No. 2 in SER Section 3.0.3.2.3. The applicant's response to A/LAI No. 7 also states that the hold down springs are fabricated from martensitic SS, as discussed in A/LAI No. 5. The applicant stated that the hold down spring components are in compression and classified as "No Additional Measures" components per MRP-191, Table 6-5. The staff finds this acceptable, as discussed in the staff's evaluation of the applicant's response to A/LAI No. 5 in SER Section 3.0.2.3.

The staff determined that the purpose of A/LAI No. 7 was to provide assurance that for RVI components fabricated from CASS materials, martensitic SS materials, and precipitation hardened SS materials, the applicant had performed plant-specific analysis or evaluation which demonstrated that the MRP-227-A recommended inspections will ensure that the structural integrity and functionality of these RVI components is maintained during the period of extended operation. The staff finds that, when taken into account with the information provided for resolving the requests in A/LAI No. 2 and No. 5, the applicant had adequately addressed A/LAI No. 7 because the staff confirmed that the applicant demonstrated that its RVI components fabricated from the above referenced materials will be adequately managed during the period of extended operation in accordance with the recommendations of MRP-227-A, without the need for submitting additional component-specific flaw tolerance, susceptibility or functionality analyses to the staff for approval. The staff finds acceptable that loss of fracture toughness due to thermal embrittlement or neutron irradiation embrittlement does need to be managed for the lower support column bodies because the staff confirmed the components are not made from CASS materials. The staff further finds acceptable that supplemental flaw tolerance, susceptibility, or functionality analyses would not need to be submitted for the other RVI components made from CASS, martensitic SS, or precipitation hardened SS because the staff confirmed that the components were appropriately evaluated and dispositioned in MRP-191 as "No Additional Measures" components. A/LAI No. 7 is resolved.

8. The staff reviewed the applicant's response to A/LAI No. 8, as documented in LRA Appendix C. The staff notes that A/LAI No. 8 includes Items 1 – 5 and each item is reviewed separately, as documented below.

A/LAI No. 8, Item 1, states that an AMP for the facility that addresses the 10 program elements as defined in NUREG-1801, Revision 2, AMP XI.M16A is to be provided in the LRA. The staff noticed that the applicant's response to A/LAI No. 8, Item 1, stated that the AMP that addresses the 10 program elements as defined in NUREG-1801, Revision 2, AMP XI.M16A, is submitted as LRA Appendix B, Section B.2.1.7.

The staff determined that the purpose of A/LAI No. 8, Item 1, is to ensure that the applicant provided an AMP that addressed the 10 program elements of GALL AMP XI.M16A, including any applicable license renewal interim staff guidance. The staff finds that the applicant has adequately addressed A/LAI No. 8, Item 1, because the staff confirmed the applicant has included its PWR Vessel Internals program in LRA Section B.2.1.7 and that the AMP is consistent with the updated version of GALL AMP XI.M16A in LR-ISG-2011-04. The staff's review of the applicant's PWR Vessel Internals Program is documented in SER Section 3.0.3.2.3.

A/LAI No. 8, Item 2, states that to ensure the MRP-227 program and the plant-specific action items will be carried out, the applicant is to submit an inspection plan which addresses the identified plant-specific action items for staff review and approval consistent with the licensing basis for the plant. The applicant's response to A/LAI No. 8, Item 2, stated the PWR RVIs inspection plan with plant-specific activities for the primary components, expansion components, existing program components, and examination acceptance and expansion criteria was provided in Tables A through D of LRA Appendix C. In addition, the applicant stated that its inspection plan for the PWR Vessel Internals components is consistent with the guidance specified in MRP-227-A for corresponding components.

The staff determined that the purpose of A/LAI No. 8, Item 2, is to ensure the applicant identifies those components that are managed by the PWR Vessel Internals program and to address the applicant's response to the plant-specific action items (i.e., A/LAIs) for MRP-227-A. The staff noticed that the applicant's inspection plan consists of its PWR Vessel Internals program, LRA Appendix C, Tables A through D, responses to A/LAIs and AMR results identified in LRA Table 3.1.2-3. The staff's review of the applicant's PWR Vessel Internals program and responses to A/LAIs are documented in SER Section 3.0.3.2.3. The staff's review of the applicant's AMR results is documented in SER Section 3.1.

The staff noticed that LRA Appendix C provides the PWR Vessel Internals Inspection Plan that is outlined in Tables A through D.

- Table A specifies the vessel internal components classified as Primary components and is based on MRP-227-A, Table 4.3.
- Table B specifies the vessel internal components classified as Expansion components and is based on MRP-227-A, Table 4.6.
- Table C specifies the examination acceptance and expansion criteria and is based on MRP-227-A, Table 5.3.
- Table D specifies the components that are classified as Existing Program components.

The staff noticed that, although LRA Appendix C, Tables A and B, are based on MRP-227-A, they include the management of aging effects that were not identified in MRP-227-A, Tables 4.3 and 4.6. In addition, the staff noticed that LRA Appendix C, Table C, provides the "examination acceptance criteria," "expansion criteria," and "additional examination acceptance criteria" for Primary and Expansion components, but only for those aging effects that were identified and evaluated in MRP-227-A, Tables 4.3 and 4.6.

For example, the staff noticed that Table 4-3 of the MRP-227-A report identifies that the control rod guide plates (guide cards) in the CRGT assembly are managed for loss of material due to wear as a "Primary" component. However, the staff noticed that Table A of LRA Appendix C identifies that the control rod guide cards are managed for loss of material, cracking, loss of fracture toughness, and changes in dimensions. The staff noticed that this is only an example and is not the only instance in which the applicant proposed the management of aging effects beyond those discussed in MRP-227-A. Since the applicant has identified aging effects that were not addressed in MRP-227-A, Tables 4.3 and 4.6, the staff noticed that the program may not currently include suitable inspections and proper acceptance and examination criteria to manage these additional aging effects. The applicant's proposal to manage these additional aging effects not addressed in MRP-227-A is conservative; however, the staff determined that in order for the applicant's program to adequately manage these additional aging effects, it is necessary for the program and inspection plan to establish the appropriate inspection, acceptance and examination criteria.

By letter dated December 12, 2013, the staff issued RAI B.2.1.7-5 requesting that the applicant establish and justify that appropriate inspections will be performed to adequately manage these additional aging effects for those additional effects that are not addressed in MRP-227-A but are outlined in the PWR Vessel Internals Inspection Plan.

In its response, by letter dated January 13, 2014, the applicant stated additional aging effects not addressed by the inspection recommendations contained in MRP-227-A, Tables 4-3 and 4-6 were included in the BBS PWR Vessel Internals Inspection Plan as part of the screening process. The applicant stated that the impact of these additional aging effects were evaluated for the associated components in MRP-227-A which determined that the susceptibility to degradation, the likelihood of failure, or consequence of failure of the components due to the additional aging effects were of minimal significance. The applicant further stated, although the impact of an aging effect was determined to be of minimal significance, any indication of a lesser significant aging effect occurring should be noted and evaluated. The applicant added clarifying notes to the BBS PWR Vessel Internals Inspection Plan, LRA Appendix C, Tables A and B. The applicant added Notes 2, 3, and 4, which state that the impact of the aging effects of Loss of Fracture Toughness, Changes in Dimensions, and Cracking was determined to be of minimal significance for the associated component per MRP-191 and MRP 227-A, and that for this reason, pre-defined acceptance criteria and expansion criteria are not necessary. The notes further state that if any indication of degradation due to these aging effects is observed during the scheduled component examination, the condition should be entered into the CAP and evaluated. The staff finds this acceptable because the applicant clarified in the LRA that the impact of these additional aging effects, which are not addressed in MRP-227-A, is of minimal significance. The staff noticed that the applicant's approach is conservative by incorporating any indication of these additional aging effects into its corrective actions program and will be managing the aging effects recommended by MRP-227-A for these components. The staff determined that the basis is consistent with the MRP's program basis for evaluating OE, as given in Section 7 of the MRP-227-A report and, therefore, conforms to the expectations of the "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience" program elements in GALL Report AMP XI.M16A. The applicant also added Note 1 to the BBS PWR Vessel Internals Inspection Plan for the Baffle-to-Former Assembly: Accessible Baffle-to-Former Bolts item in Table A to address MRP-227-A, Table 4-3, Note 6. The added Note 1 states that the aging effect of Change in Dimensions, due to void swelling, on associated components is managed through management of change in dimensions, due to void swelling, on the entire baffle-former assembly, which the staff confirmed is consistent with MRP-227-A. The staff's concerns in RAI B.2.1.7-5 are resolved.

The staff finds that the applicant has adequately addressed A/LAI No. 8, Item 2, by providing all necessary information for the staff's review regarding its inspection plan for the RVIs, as described above.

A/LAI No. 8, Item 3, states that an applicant referencing MRP-227-A for its RVIs component AMP shall ensure that the programs and activities specified as necessary in MRP-227-A are summarily described in the UFSAR supplement. The applicant's response to A/LAI No. 8, Item 3, states that the UFSAR Supplement is included in LRA Appendix A, Section A.2.1.7, and includes a summary of the program and activities specified as necessary for the PWR Vessel Internals (B.2.1.7) program.

The staff determined that the purpose of A/LAI No. 8, Item 3, was to ensure that the use of MRP-227-A to manage the effects of aging on the RVIs was summarized in the UFSAR supplement in accordance with 10 CFR 54.21(d). The staff finds that the applicant has adequately addressed A/LAI No. 8, Item 3, because the applicant provided a summary of its PWR Vessel Internals Program, including the use of MRP-227-A, in the UFSAR supplement in

LRA Section A.2.1.7. The staff's review of LRA Section A.2.1.7 is documented below in the "UFSAR Supplement" subsection of SER Section 3.0.3.2.3.

A/LAI No. 8, Item 4, states that 10 CFR 54.22 requires the applicant to submit any TS changes that are necessary to manage the effects of aging during the period of extended operation. In addition, it states if the mandated requirements in the operating license or facility TS differ from the recommended criteria in MRP-227-A, the mandated requirements take precedence over the MRP-227-A recommendations and shall be complied with. The applicant's response to A/LAI No. 8, Item 4, states no technical specification changes are required for BBS based on MRP-227-A and the associated safety evaluation.

The staff determined that the purpose of A/LAI No. 8, Item 4, is to ensure that if the mandated inspection or analysis requirements for the RVIs, if any exist, differ from the recommended criteria in MRP-227-A. The mandated requirements take precedence over the MRP-227-A recommendations. The staff reviewed the applicant's operating license and TS for Units 1 and 2 and confirmed that it does not contain mandated requirements for analysis or inspection of the RVIs. In addition, the staff did not identify any required changes to the TS as a result of I&E guidelines in MRP-227-A. The staff finds that the applicant has adequately addressed A/LAI No. 8, Item 4, because the staff confirmed that no mandated requirements for analysis or inspection of the RVIs exist and no changes to the applicant's TS are necessary as a result of MRP-227-A.

A/LAI No. 8, Item 5, states, in part, for those cumulative usage factor (CUF) analyses that are TLAAs for RVIs, the acceptance of these TLAAs may be done in accordance with either 10 CFR 54.21(c)(1)(i) or (ii), or in accordance with 10 CFR 54.21(c)(1)(iii) using the applicant's program that corresponds to NUREG-1801, Revision 2, AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary Program." To satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121, A/LAI No. 8, Item 5, states that the existing fatigue CUF analyses shall include the effects of the reactor coolant water environment. The applicant's response to A/LAI No. 8, Item 5, states the Fatigue Monitoring Program will be enhanced to evaluate the effects of the reactor coolant water environment on the RVI components with existing fatigue CUF analyses to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121.

The staff determined that based on the applicant's response to A/LAI No. 8, Item No. 5, it is not clear how the applicant is addressing effects of the reactor coolant water environment on the RVI components with existing fatigue CUF analyses. The applicant did not identify the specific approach or method in which the Fatigue Monitoring program will evaluate the RVI components with existing fatigue CUF analyses to address the effects of reactor coolant water environment. By letter December 12, 2013, the staff issued RAI B.2.1.7-4 requesting that the applicant indicate the RVI components with existing CUF analyses for which the Fatigue Monitoring Program will evaluate the effects of reactor coolant water environment and provide the associated material type and CUF value for each component. In addition, the applicant was requested to describe and justify the approach and method that will be used to address the effects of reactor coolant water environment on the RVI components with existing fatigue CUF analyses.

In its response January 13, 2014, the applicant stated that the Fatigue Monitoring Program will evaluate the effects of the reactor coolant water environment for the following RVI components with existing CUF analyses: upper core plate, upper core plate alignment pins, upper support plate, baffle plate, core barrel nozzle, lower radial restraints, lower core plate, and lower support columns. The applicant also provided the CUF values and material type for each of these components. The staff confirmed that the associated CUF values were all below the acceptance criteria of 1.0. The applicant further stated that the methodology and approach to address the effects of the reactor coolant water environment on the RVI components will be consistent with that used to evaluate RCPB components described in LRA Section 4.3.4. The applicant stated that each of the RVI components with existing CUF analyses will be evaluated by applying environmental fatigue multipliers determined in accordance with the methodologies in NUREG/CR-5704 and NUREG/CR-6909, which is consistent with the recommendations of GALL Report AMP X.M1. The staff's evaluation of the applicant's use of these reports is documented in SER Section 4.3.4.2.

The staff finds the applicant's response acceptable because the applicant is using its Fatigue Monitoring Program to address the effects of the reactor coolant water water environment for RVI components that include existing CUF analyses by the application of an appropriate environmental fatigue multiplier. The staff's concern in RAI B.2.1.7-4 is resolved.

The staff determined that the purpose of A/LAI No. 8, Item 5, is to ensure that environmentally assisted fatigue (EAF) is addressed for those components that have an existing CUF analyses. The staff finds that the applicant has adequately addressed A/LAI No. 8, Item 5, because as part of its enhanced Fatigue Monitoring Program, the calculations for the RVI with existing CUF analyses will be evaluated for the effects of the reactor coolant water water environment using guidance recommended in GALL Report AMP X.M1 (i.e., NUREG/CR-5704 and NUREG/CR-6909).

Based on its audit, the staff finds that program elements 1 through 9 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M16A, as revised by Final LR-ISG-2011-04. The staff also reviewed the exception associated with the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," and "confirmation process," and "administrative controls" program elements, and its justification, and finds that the AMP is consistent with Final LR-ISG-2011-04 and is adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B.2.1.7 summarizes OE related to the PWR Vessel Internals Program.

The staff noticed that the applicant's program relies on MRP-227-A, which includes provisions in Section 7.6 that each commercial U.S. PWR unit shall provide a summary report of all inspections and monitoring, items requiring evaluation, and new repairs to the MRP for PWR internals within the scope of MRP-227-A that are examined. The staff noticed that this aspect of MRP-227-A ensures that information from RVI inspections from the commercial U.S. PWR fleet is shared and communicated so that potential significant issues are addressed across the fleet, fleet trends are identified, and any needed revisions to MRP-227-A are determined.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of an RAI, as discussed below.

The staff noticed that LRA Table 3.1.2-3, Reactor Vessel Internals, indicates that the clevis insert bolts are made from nickel alloy X-750 materials and that cracking of the clevis insert bolts will be managed by the PWR Vessel Internals program. In addition, the staff noticed that Table D in LRA Appendix C indicates that the clevis insert bolts are managed by inspections performed in accordance with ASME Code, Section XI, Category B-N-3. Appendix A to MRP-227-A indicates that failures of Alloy X-750, precipitation-hardenable nickel-chromium alloy, clevis insert bolts were reported by one Westinghouse designed plant in 2010. Furthermore, the staff noticed that these clevis insert bolts failed because of cracking, which is an aging effect that was not addressed in MRP-227-A, the only aging mechanism requiring management by MRP-227-A for the clevis insert bolts is wear; and the bolts are categorized as an "Existing Programs" component. Thus, under MRP-227-A, the clevis insert bolts will be inspected in accordance with the ASME Code, Section XI Inservice Inspection Program, to manage the effects due to wear only.

The staff noticed that the ASME Code, Section XI, specifies a VT-3 visual inspection for the clevis insert bolts, which may not be adequate to detect cracking before bolt failure occurs. In addition, since cracking of the clevis insert bolts was not addressed during the development of MRP-227-A, it is not clear to the staff whether this OE is applicable to the applicant nor whether the PWR Vessel Internals program will need to be modified to account for this OE.

By letter dated December 12, 2013, the staff issued RAI B.2.1.7-6 requesting that the applicant specify the fabrication material, including any applicable heat treatment, for the clevis insert bolts at BBS, Units 1 and 2. In addition, the staff requested that the applicant discuss and justify whether the OE associated with cracking of the clevis insert bolts is applicable to BBS, Units 1 and 2.

In its response, by letter dated January 13, 2014, the applicant stated that the OE associated with the cracking of clevis insert bolts in 2010 at another Westinghouse-designed plant is not directly applicable to BBS, Units 1 and 2. The applicant stated that the BBS clevis insert design and heat treatment of the clevis insert design both differ from that of the other Westinghouse plant. The applicant stated that BBS uses the Westinghouse Type 2 design for the clevis insert, whereas the other Westinghouse plant uses the Westinghouse Type 4 clevis insert design. The applicant stated that BBS clevis insert bolts are subject to a heat treatment typically referred to as low-temperature annealed and aged condition (BH) which differs from the heat treatment that is similar to the equalized and aged condition (AH) process applied at the other Westinghouse plant. The applicant noted that there are no known failures of clevis insert bolts in plants that use the clevis insert design and heat treatment used at BBS. The applicant further stated that the last ASME Section XI ISI at BBS was reviewed which confirmed that there were no documented indications of clevis insert wear or missing lock bars. The applicant stated that the failed clevis insert bolt industry OE was entered into the BBS CAP and that it will continue to evaluate industry OE, such as the ongoing root cause analysis of the failed clevis insert bolts at the other plants, for applicability to BBS as part of the OE program.

The staff finds this response acceptable because the applicant confirmed that the last ASME Section XI ISI did not detect any wear or missing lock bars on the clevis insert bolts; and therefore, the current ASME Section XI basis is sufficient to monitor cracking and wear in the clevis insert bolts. The staff noticed that the low-temperature annealed and aged heat treatment applied to the clevis insert bolts at BBS is still susceptible to PWSCC; however, the clevis insert assembly is within the scope of ASME Section XI ISI. The staff noticed that the applicant will use its OE program to determine if future plant-specific OE associated with aging effects for the clevis insert assembly will require augmentation of the PWR Vessel Internals Program inspection activities. The staff's concern in RAI B.2.1.7-6 is resolved.

Based on its audit, its review of the application, and its review of the applicant's response to RAI B.2.1.7-6, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M16A was evaluated.

<u>UFSAR Supplement</u>. 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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, as revised by Draft LR-ISG-2011-04 and Final LR-ISG-2011-04. The staff also noticed that the applicant committed to implement the new program no later than the date that the renewed operating licenses are issued for managing the effects of aging for applicable components.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's PWR Vessel Internals program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. The staff concludes that the applicant 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 Bolting Integrity

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.9 describes the existing Bolting Integrity Program as consistent, with enhancements, with GALL Report AMP XI.M18, "Bolting Integrity." The LRA states that the AMP addresses loss of preload, cracking, and loss of material of closure bolting on pressure retaining joints. The LRA also states that the AMP proposes to manage these aging effects through periodic visual inspections for leakage of all bolted connections and volumetric, surface, and visual inspections of ASME Code Class 1, 2, and 3 bolts, nuts, washers, and other bolting components in accordance with ASME Section XI, Subsections IWB, IWC, and IWD. The LRA further states that inspection activities of closure bolting in submerged environments will be performed in conjunction with component maintenance activities.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M18.

For the "scope of program" program element, the staff found that the LRA includes AMR items for structural bolting that is managed by the Bolting Integrity Program, which is inconsistent with the scope of GALL Report AMP XI.M18. LRA Table 3.1.2-2 credits the Bolting Integrity Program to manage the aging of bolts that fasten mechanical elements of the integral reactor vessel head assembly. In addition, LRA Table 3.3.2-12, as revised by letter dated July 18, 2014, credits the Bolting Integrity Program to manage the aging of the bolts that fasten the baskets of the travelling screens in the Braidwood Station lake screen house intake bay. The staff's evaluations of the aging management activities for structural bolting associated with the reactor head assembly and travelling screens are documented in SER Sections 3.1.2.1.4 and 3.3.2.3.12, respectively.

For the "scope of program" program element, the staff noticed that the applicant's program includes the inspection of normally inaccessible bolting in submerged water environments, which is not specifically addressed in the GALL Report AMP. The staff's evaluation of this aspect of the applicant's program is discussed below.

GALL Report AMP XI.M18 includes periodic visual inspections of bolted connections at least once per refueling cycle. The staff noticed that the premise of this methodology is that the inspection locations are accessible. GALL Report AMP XI.M18 does not specifically address inaccessible components. GALL Report recommendations for inaccessible components in other AMPs include opportunistic inspections that are performed when components are made accessible during maintenance. GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" (as revised by LR-ISG-2012-02) also recommends that a representative sample of a minimum of 20 percent of components, with a maximum of 25, be inspected every 10 years to ensure that each material, environment, and aging effect combination is addressed.

During its audit, the staff noticed that the applicant's Bolting Integrity Program includes the inspection of closure bolting in pressure retaining joints in submerged raw water environments, which will be performed in conjunction with component maintenance activities. The staff evaluated whether these component maintenance activities will be performed with sufficient frequency such that bolting degradation can be identified prior to loss of intended function. Because the raw water environments are not identical for BBS, the staff evaluated each station separately.

Byron Station Submerged Bolting. As documented in the Audit Report for the Bolting Integrity Program, the staff noticed that steel bolting exposed to raw water in the Byron Station demineralized water system (associated with the well water system deep well pumps) will be available for inspection every 10 years during pump rebuilds. The staff also noticed that the SS bolting exposed to raw water in the service water and fire protection system pumps will be available for inspection every 18 months to 8 years, depending on the specific pump, during maintenance activities. The staff further noticed that Byron Station did not yet have established maintenance intervals for the fire protection jockey pumps, as the inspection of the bolting for these pumps is an enhancement to the applicant's Bolting Integrity Program. The staff found that, even with the undetermined inspection interval for the fire protection jockey pumps, a representative sample of both steel and SS bolting exposed to raw water at Byron Station will be inspected at intervals that are generally consistent with GALL Report guidance for inaccessible components (at least every 10 years).

Braidwood Station Submerged Bolting. As documented in the Audit Report for the Bolting Integrity Program, the staff noticed that SS bolting exposed to raw water in the Braidwood Station fire protection system will be available for inspection every 3 to 15 years, depending on the specific pump, during maintenance activities. As a result, the staff found that a representative sample of SS bolting exposed to raw water at Braidwood Station will be inspected at intervals that are generally consistent with GALL Report guidance for inaccessible components (at least every 10 years).

Summary of Submerged Bolting. Based on its audit observations, the staff finds that the applicant's program provides sufficient opportunity to inspect submerged bolting such that degradation can be detected prior to loss of intended function. The staff noticed that the scheduled maintenance for the associated submerged well water, service water, and fire protection pumps provides for a representative sample of steel and SS bolting to be inspected at a frequency that is generally consistent with GALL Report guidance for normally inaccessible components in other AMPs.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.9 includes an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" program elements. The applicant stated that the use of lubricants containing molybdenum disulfide on pressure retaining bolted joints will be prohibited. GALL Report AMP XI.M18 states that molybdenum disulfide (MoS_2) as a lubricant should not be used. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because when it is implemented it will make the program consistent with the GALL Report AMP.

Enhancement 2. LRA Section B.2.1.9 includes an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" program elements. The applicant stated that the use of high strength bolting (actual measured yield strength greater than 150 ksi) for pressure retaining bolted joints will be prohibited. GALL Report AMP XI.M18 states that preventive measures include using bolting material that has an actual measured yield strength limited to less than 150 ksi. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because when it is implemented it will make the program consistent with the GALL Report AMP.

Enhancement 3 (Byron). LRA Section B.2.1.9 includes an enhancement to the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements. The applicant stated that it will perform visual inspections of submerged bolting on Byron Station fire protection system pumps and well water system deep well pumps when submerged portions of the pumps are overhauled or replaced during maintenance activities. The staff's evaluation of the inspection of submerged bolting is documented above. In that evaluation, the staff found that maintenance activities will provide for a representative sample of bolting to be visually inspected at a frequency that is sufficient to detect aging prior to loss of intended function; therefore, the staff finds this enhancement acceptable.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M18. In addition, the staff reviewed the enhancements associated with the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.9 summarizes OE related to the Bolting Integrity Program. In 2002, Byron Station experienced a leak on a containment ventilation system flange. The immediate corrective action was to tighten the flange. After a followup investigation, the associated soft neoprene gaskets were replaced with spiral wound gaskets on similar flanges on both units to prevent the flange bolt loosening that had occurred over time due to vibration and cyclic operation of an upstream valve. In 2005, minor leakage was identified on the flange of the closed cooling heat exchanger at Byron Station during a routine walkdown. The flange was retorqued and the joint was verified later to be leak tight. In 2006, mechanics at Braidwood Station noticed that one flange bolt on the fill line to the SFP demineralizer did not have full thread engagement. No leakage was observed; however, an immediate corrective action was taken to tighten the bolts on the connection to achieve additional gasket compression. Later, the connection was disassembled, inspected, cleaned, and reassembled with a new gasket and an appropriately long bolt (the subject bolt was short).

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M18 was evaluated.

UFSAR Supplement. LRA Section A.2.1.9, as revised by letter dated August 29, 2014, provides the UFSAR supplement for the Bolting Integrity Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Bolting Integrity Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 Steam Generators

Summary of Technical Information in the Application. LRA Section B.2.1.10 describes the existing Steam Generators Program as consistent, with an exception and enhancements, with GALL Report AMP XI.M19, "Steam Generators." The Steam Generators Program is a preventive, mitigative, condition monitoring, and performance monitoring program that provides for managing aging of the steam generator tubes, plugs, and secondary-side components that are contained within the steam generator. The LRA states that aging is managed through assessment of potential degradation mechanisms, inspections, tube integrity assessments, tube plugging and repairs, primary to secondary leakage monitoring, maintenance of secondary-side internal components, primary and secondary side water chemistry, and foreign material exclusion. The LRA further states that the program requirements are consistent with the requirements of the plant TSs, the Maintenance Rule, 10 CFR 50.65, ASME Code, and EPRI steam generator guidelines EPRI 1019038, "Steam Generator Integrity Assessment Guidelines," EPRI 1013706, "Steam Generator Examination Guidelines," EPRI 1022832, "PWR Primary-to-Secondary Leak Guidelines," and EPRI 1014983, "Steam Generator In-Situ Pressure Test Guidelines." The EPRI guidelines provide a generic industry approach to implementing NEI 97-06, "Steam Generator Program Guidelines."

The LRA states that the program includes preventive measures to mitigate age-related degradation through foreign material exclusion as a means to inhibit wear degradation and secondary-side maintenance activities (e.g., sludge lancing) for removing deposits that may contribute to degradation. In addition, the Steam Generators Program detects flaws in steam generator tubes, plugs, and tube supports needed to maintain tube integrity. The LRA states that NDE techniques are used to inspect all steam generator tubes to identify tubes that may need to be removed from service or repaired in accordance with plant TSs.

The LRA states that the original Byron and Braidwood, Unit 1, Westinghouse Model D-4 steam generators were replaced in 1998. The replacement steam generators (RSGs) incorporate features designed to improve reliability and minimize age-related degradation. The original Byron and Braidwood, Unit 2, Westinghouse Model D-5 steam generators are currently in service.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M19.

The staff also reviewed the portions of the "parameters monitored or inspected," program element 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 the exception and enhancements follows.

Exception 1. LRA Section B.2.1.10 includes an exception to the "parameters monitored or inspected," program element. The applicant stated that GALL Report specifies the use of EPRI 1008219, "Steam Generator Primary-to-Secondary Leakage Guidelines," Revision 3, for monitoring primary to secondary leakage, however the BBS existing Steam Generators AMP specifies the use of EPRI 1022832, "Steam Generator Primary-to-Secondary Leakage Guidelines," Revision 4, for monitoring primary-to-secondary leakage. The LRA states that the major changes to Revisions 4 include: (1) clearly identifying the use of two methodologies, leakage rate-of-change methodology and constant leakage methodology; (2) clarification of the continuous radiation monitor definition to include continuous operation with an alarm function in the Control Room; (3) the frequency of grab samples was updated based on leak rate; and (4) actions with and without radiation monitors were clarified. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M19 and finds it acceptable because the major changes included in Revision 4 provide updated information on technical bases and clarifies monitoring requirements for implementation based on lessons learned. Revision 4 provides the most recent industry guidance for the monitoring of primary-to-secondary leakage and did not reduce the level of monitoring for leakage.

Enhancement 1. LRA Section B.2.1.10 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that it will validate that PWSCC of the divider plate welds to the primary head and tubesheet cladding does not occur. The applicant commits to perform one of the following three resolution options for Units 1 and 2:

> Option 1: Inspection
>
> Perform a one-time inspection, under the Steam Generators (B.2.1.10) Program, of each steam generator to assess the condition of the divider plate welds and the effectiveness of the Water Chemistry (B.2.1.2) Program. For the Byron and Braidwood, Unit 1, steam generators which were replaced in 1998, the inspection will be performed between 2018 and the start of the period of extended operation to allow the steam generators to acquire at least twenty years of service. For the Byron and Braidwood, Unit 2, steam generators, which currently have at least twenty years of service, the inspection will be performed prior to entering the period of extended operation. The examination techniques(s) will be capable of detecting PWSCC in the divider plate assemblies and associated welds.
>
> or
>
> Option 2: Analysis
>
> Perform an analytical evaluation of the steam generator divider plate welds in order to establish a technical basis which concludes that the steam generator reactor coolant pressure boundary is adequately maintained with the presence of steam generator divider plate weld cracking. The analytical evaluation will be submitted to the Nuclear Regulatory Commission (NRC) for review and approval prior to entering associated period of extended operation.
>
> or
>
> Option 3: Industry and NRC Studies
>
> If results of industry and NRC studies and operating experience document that potential failure of the steam generator reactor coolant pressure boundary due to PWSCC of the steam generator divider plate welds is not a credible concern, this commitment will be revised to reflect that conclusion.

For this enhancement, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

LRA Section B.2.1.10 Enhancement 1 provides three options the applicant may take to disposition potential PWSCC of the BBS steam generator divider plate welds to the primary head and tubesheet cladding. The second option for Enhancement 1 indicates that an analytical evaluation will be performed to establish a technical basis to disposition the potential degradation mechanism. By letter dated February 7, 2014, the staff issued RAI B.2.1.10-1 requesting that the applicant provide a period by which the analytical evaluation will be provided to the staff such that the staff will have adequate time to review and approve it before the plants enter the period of extended operation.

In its response dated March 4, 2014, the applicant stated that if option 2 is taken, it will provide the analysis 2 years prior to entering the associated period of extended operation. The staff finds the applicant's response acceptable because the period the applicant provided will allow the staff to review and disposition the analysis prior to the plant entering the period of extended operation. The staff's concern described in RAI B.2.1.10-1 is resolved.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M19 and finds it acceptable because when it is implemented it will validate that PWSCC of the divider plate welds to the primary head and tubesheet cladding does not occur.

Enhancement 2. LRA Section B.2.1.10 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that it will validate that PWSCC of the tube-to-tubesheet welds does not occur at Byron and Braidwood, Unit 1. The applicant commits to perform one of the following three resolution options for Unit 1:

> Option 1: Inspection
>
> Perform a one-time inspection, under the Steam Generator (B.2.1.10) Program, of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. Since the BBS, Unit 1, steam generators were replaced in 1998, the inspection will be performed between 2018 and the start of the period of extended operation to allow the steam generators to acquire at least twenty years of service. The examination technique(s) will be capable of detecting primary water stress corrosion cracking in the tube-to-tubesheet welds. If cracking is identified, the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.
>
> or
>
> Option 2: Analysis – Susceptibility
>
> Perform an analytical evaluation of the steam generator tube-to-tubesheet welds to determine that the welds are not susceptible to primary water stress corrosion cracking. The evaluation for determining that the tube-to-tubesheet welds are not susceptible to primary water stress corrosion cracking will be submitted to the NRC for review and approval prior to entering the associated period of extended operation.
>
> or
>
> Option 3: Analysis – Pressure Boundary

Perform an analytical evaluation of the steam generator tube-to-tubesheet welds redefining the reactor coolant pressure boundary of the tubes, where the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted to the NRC for review and approval prior to entering the associated period of extended operation.

For this enhancement, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

LRA Section B.2.1.10 Enhancement 2 provides three options the applicant may take to validate that PWSCC of the tube-to-tubesheet welds does not occur at BBS, Unit 1. Options 2 and 3 of this enhancement indicate that an analytical evaluation will be performed to determine that the steam generator tube-to-tubesheet welds are not susceptible to PWSCC or redefine the RCPB of the tubes. By letter dated February 7, 2014, the staff issued RAI B.2.1.10-1 requesting that the applicant provide a period by which the analytical evaluation will be provided to the staff such that the staff will have adequate time to review and approve it before the plants enter the period of extended operation.

In its response dated March 4, 2014, the applicant stated that if options 2 or 3 are taken, it will provide the analysis 2 years prior to the period of extended operation. The staff finds the applicant’s response acceptable because the period the applicant provided will allow the staff to review and disposition the analysis prior to the plant entering the period of extended operation. The staff’s concern described in RAI B.2.1.10-1 is resolved.

Based on its audit, and review of the applicant’s response to RAI B.2.1.10-1, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M19. The staff also reviewed the exception associated with the “parameters monitored or inspected,” program element, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the “parameters monitored or inspected,” program element and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B.2.1.2 summarizes OE related to the Steam Generators Program.

The applicant provided the following OE:

<u>*Byron Station*</u>. The LRA states that the four Byron, Unit 1, original equipment Westinghouse Model D-4 steam generators were replaced with B&W recirculating feedring RSGs during the Byron, Unit 1, Fall 1997 through the spring 1998 Refueling Outage. The LRA further states that each Unit 1 steam generator contains 6,633 thermally treated Alloy 690 tubes. Based on steam generator inspections up to and including the Byron Station, Unit 1, Spring 2011 Refueling Outage, a total of 21 tubes out of 26,532 tubes (approximately 0.08 percent) have been removed from service by plugging. The LRA states that of the 21 plugged tubes, 1 tube was plugged during initial construction and 20 tubes were plugged due to wear from foreign objects.

The LRA states that the four Byron, Unit 2, original equipment Westinghouse D-5 steam generators are currently in service. Each steam generator contains 4,570 thermally treated Alloy 600 U-tubes. As of the fall 2011 Refueling Outage, the LRA states that a total of

408 tubes out of 18,280 tubes (2.23 percent) have been removed from service by plugging. Of the 408 plugged tubes, 29 tubes were plugged due to top of tubesheet circumferential indications, 138 tubes were plugged due to anti-vibration bar wear, five tubes were plugged due to outside diameter volumetric indications near tube support plates, and 68 tubes were plugged due to other reasons such as preventive plugging due to unretrieved foreign objects and preheater wear.

The LRA states that during the Byron, Unit 2, Fall 2008 Refueling Outage, steam generator eddy current testing identified indications of SCC in the bottom quarter of the tubesheet on all four steam generators. Subsequently, the inspection scope was expanded to 100 percent of the hot leg tube ends and 20 percent of the cold leg tube ends. The LRA states that 65 hot leg tube ends were identified as having indications of cracking and none of the cold leg tube ends inspected had indications of cracking. Based on the staff-approved interim alternate repair criteria, none of the 65 tubes with indications of cracking required plugging. The applicant identified tube end cracking as a potential degradation mechanism in the degradation assessment performed prior to the refueling outage.

Braidwood Station. The LRA states that the four Braidwood, Unit 1, original equipment Westinghouse Model D-4 steam generators were replaced with B&W recirculating feedring RSGs during the Braidwood, Unit 1, Fall 1998 Refueling Outage. The LRA further states that each Unit 1 steam generator contains 6,633 thermally treated Alloy 690 tubes. Based on steam generator inspections up to and including the Braidwood Station, Unit 1, Spring 2011 Refueling Outage, a total of 85 tubes out of 26,532 tubes (approximately 0.3 percent) have been removed from service by plugging. The LRA states that of the 85 plugged tubes, 3 tubes were plugged preservice, 1 tube was plugged due to fan bar wear, 26 tubes were plugged due to wear from foreign objects, and 55 tubes were preventively plugged due to unretrieved foreign objects.

The LRA states that the four Braidwood, Unit 2, original equipment Westinghouse D-5 steam generators are currently in service. Each steam generator contains 4,570 thermally treated Alloy 600 U-tubes. As of the spring 2011 Refueling Outage, the LRA states that a total of 259 tubes out of 18,280 tubes (1.42 percent) have been removed from service by plugging. Of the 259 plugged tubes, 4 tubes were plugged due to tube support plate axial outside-diameter stress-corrosion cracking (ODSCC), 1 tube was plugged due to a tube geometric anomaly, 16 tubes were plugged due to lower tube sheet PWSCC, 15 tubes were plugged due to tope of tubesheet circumferential indications, 131 tubes were plugged due to anti-vibration bar wear, 4 tubes were plugged due to outside diameter volumetric indications near tube support plates, 71 tubes were plugged due to wear from foreign material, 2 tubes were plugged due to tube support plate wear, and 15 tubes were plugged due to other reasons such as preventive plugging due to unretrieved foreign objects and preheater wear.

During the Braidwood, Unit 2, Spring 2011 Refueling Outage, Bobbin Coil eddy current inspections were performed on the 2D steam generator. As a result of the inspection, a distorted support indication was identified at the hot leg ninth quatrefoil broached hole support plate on tube row 2, column 35. A subsequent Plus Point eddy current inspection confirmed the presence of axial ODSCC. The applicant reported that additional less severe indications were also detected at the third and fourth support plates. The affected tube was removed from service by plugging. The applicant performed a full Bobbin Coil eddy current inspection of all in-service tubes with no additional indications of ODSCC being identified. ODSCC is a degradation mechanism inspected for during scheduled eddy current test.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M19 was evaluated.

UFSAR Supplement. LRA Section A.2.1.10 provides the UFSAR supplement for the Steam Generators Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to ongoing implementation of the existing Steam Generator Program for managing the effects of aging for applicable components during the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant’s Steam Generators Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 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 an enhancement, with GALL Report AMP XI.M20, “Open-Cycle Cooling Water System.” The LRA states that the AMP addresses multiple materials, including carbon steel, copper alloy, elastomeric, cast iron, and SS, exposed to a raw water environment. The LRA also states that program activities are consistent with site commitments to GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” In addition, the LRA states that the program manages loss of material and reduction of heat transfer through condition monitoring activities such as periodic visual inspections, UT, eddy current testing, heat transfer testing, and component cleaning, and through preventive actions such as biocide and chemical treatments. As modified for RAI 3.0.3-1, by letter dated January 13, 2014, the applicant clarified the augmented aging management activities included in the program in response to questions related to recurring internal corrosion within the service water system. In addition, as modified for RAIs 3.0.3-2, 3.0.3-2a, 3.0.3-2b, and 3.0.3-2c by letters dated January 13, 2014, May 5, 2014, June 30, 2014, and August 29, 2014, respectively, the applicant clarified or provided enhancements to the program in response to questions related to loss of coating integrity.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M20. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M20 states that the inspection methods are in accordance with the applicant's docketed response to GL 89-13. However, during its audit, the staff found that the applicant's Open-Cycle Cooling Water System Program did not address certain aspects of its docketed response to GL 89-13. Specifically, in its response dated January 29, 1990, regarding the establishment of maintenance program activities to address corrosion, Exelon stated that "corrosion rates are continuously monitored with a corrator and with corrosion coupons…." However, during its review of the program basis document, the staff did not find any discussion about the use of a corrator or corrosion coupons as part of the Open-Cycle Cooling Water System Program. By letter dated April 17, 2014, the staff issued RAI B.2.1.11-1 requesting that the applicant reconcile the disparity between the program activities being performed by the sites relating to corrosion rate monitoring and the program activities described in the program basis document.

In its response dated May 15, 2014, the applicant stated that the program uses corrosion coupons to verify that representative materials are not experiencing unexpected corrosion in the associated raw water environment. In addition, the procedure, which directs activities to determine corrosion rates by periodically removing and analyzing these coupons, is currently listed as an implementing procedure in the program basis document. The applicant stated that the "monitoring and trending" program element in the program basis document will be revised to describe the corrosion coupon and corrator monitoring activities and this action is being tracked under its license renewal change request process. The staff finds the applicant's response acceptable because the activities associated with corrosion coupon monitoring, which are currently being performed by the program, will be described in the program basis document. The staff's concern described in RAI B.2.1.11-1 is resolved.

As clarified in its response dated January 13, 2014, the applicant addressed the issues in RAI 3.0.3-1 related to recurring internal corrosion by describing the existing aging management activities that are performed as part of the raw water corrosion program. The applicant stated that the raw water corrosion program was developed to address plant-specific and industry OE and it augments the sites' GL 89-13 program. The applicant also stated that, where possible, piping inspections are performed using a 100-percent scan UT method to detect localized corrosion indicative of microbiologically influenced corrosion (MIC). In addition, the applicant stated that inspection locations are selected based on several factors, including commitments made in its responses to GL 89-13, piping configuration, flow conditions, and prior inspection results. The staff noticed that the applicant revised LRA Sections A.2.1.11 and B.2.1.11 to reflect the augmented aging management activities currently being performed by the program, and additional enhancements were not warranted.

As clarified in its response dated August 29, 2014, the applicant addressed an observation from the regional inspection for NRC Inspection Procedure 71002, “License Renewal Inspection,” by revising LRA Sections A.2.1.11 and B.2.1.11. The revision clarifies that the program manages aging effects of nonsafety-related components by performing periodic inspections, including components associated with the deep well pumps at Byron. The staff understood this clarification to note that inclusion of some nonsafety-related components within the scope of this program was not due to spatial interaction concerns (i.e., leakage boundary), but because their failure could directly prevent accomplishment of a function listed in 10 CFR 54.4(a)(1) (i.e., pressure boundary). The staff considered this clarification warranted because the initial program description appeared to limit the scope of nonsafety-related components to only those that have a potential for spatial interaction with safety-related components.

The staff also reviewed the portions of the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. For the changes and enhancements that address loss of coating integrity, herein, the staff’s evaluation is documented in SER Section 3.0.3.3.1. The staff’s evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.11 includes an enhancement to the “parameters monitored or inspected” and “detection of aging effects” program elements. The applicant stated that it would perform at least four periodic volumetric inspections every refueling cycle on nonessential service water system piping in the turbine building and auxiliary building for each unit, to identify loss of material. The staff noticed that these inspections will be in addition to the 10 inspections (5 in low flow and 5 in high flow locations) that are currently included as part of the applicant’s commitments in response to GL 89-13. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because when it is implemented the program will include activities to manage loss of material in nonsafety-related portions of the service water system that have the potential for spatial interaction with safety-related components.

Enhancement 2. By letter dated May 5, 2014, in response to RAI 3.0.3-2a, the applicant included an enhancement to the “detection of aging effects” program element. The applicant stated that coating inspectors will be certified to either American National Standards Institute N45.2.6, “Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants,” or the ASTM [American Society for Testing and Materials] standards endorsed in RG 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.” The staff’s evaluation and acceptance of this enhancement is documented in SER Section 3.0.3.3.1.

Enhancement 3. By letters dated May 5, 2014, and June 30, 2014, in response to RAIs 3.0.3-2a and 3.0.3-2b, the applicant included an enhancement to the “acceptance criteria” program element. The applicant stated that indications of coating peeling, blistering, or delamination from the base metal will be entered into the CAP. The staff’s evaluation and acceptance of this enhancement is documented in SER Section 3.0.3.3.1.

Enhancement 4. By letters dated May 5, 2014, and June 30, 2014, in response to RAIs 3.0.3-2a and 3.0.3-2b, the applicant included an enhancement to the “acceptance criteria” program element for instances where degraded coatings are returned to service without repair or replacement. The program will specify adhesion testing when peeling, blistering, or delamination is detected and the coating is not repaired or replaced to ensure that the remaining coating is tightly bonded to the base metal. The staff's evaluation and acceptance of this enhancement is documented in SER Section 3.0.3.3.1.

Enhancement 5. By letter dated June 30, 2014, in response to RAI 3.0.3-2b, the applicant included an enhancement to the "monitoring and trending," "acceptance criteria," and "corrective action" program elements. The applicant stated that an evaluation, considering the potential for downstream flow blockage and loss of material will be conducted whenever indications of peeling, blistering, and delamination are observed during a coating inspection and the coating will be returned to service without repair or replacement. The staff's evaluation and acceptance of this enhancement is documented in SER Section 3.0.3.3.1.

Enhancement 6. By letter dated June 30, 2014, in response to RAI 3.0.3-2b, the applicant included an enhancement to the "monitoring and trending" and "corrective action" program elements. The applicant stated that the as-left condition of coatings will minimize the potential for further degradation, whenever degraded coatings exhibit signs of peeling, blistering, or delamination and are returned to service without repair or replacement. The staff's evaluation and acceptance of this enhancement is documented in SER Section 3.0.3.3.1.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.11-1, 3.0.3-1, 3.0.3-2, 3.0.3-2a, and 3.0.3-2b, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M20 and the staff's recommended actions to manage loss of coating integrity as described in SER Section 3.0.3.3.1. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.11 summarizes OE related to the Open-Cycle Cooling Water System Program. For Byron, the LRA describes a monthly operability test in 2006 for the essential service water makeup pump where site personnel identified a through-wall leak in a 2-in. pipe for the pump's water jacket cooling. Further evaluation determined that MIC caused the leak, and subsequent extent of condition reviews identified additional degradation on both trains. Corrective actions included replacing the leaking pipe segment and establishing a new preventive maintenance task to UT the affected pipe segments every 10 years. For Braidwood, the LRA describes inspections in 2011 related to GL 89-13 where site personnel found clam shells in a portion of essential service water piping that serves as the safety-related water source for the 2A AFW system. Based on the volume of shells, the 2A train was declared inoperable, but the extent of condition inspections for the other Unit 2 train and both Unit 1 trains did not identify any other fouling. Corrective actions included flushing to remove the shells, revising the service water heat exchanger inspection procedures to incorporate additional guidance on macro-fouling and biological fouling, and revising the AFW valve stroke surveillances to clarify actions for the discovery of debris in the system. The applicant's review of plant-specific OE related to this program did not reveal any adverse trends, did not identify problems that significantly impacted safe operation, and found that adequate corrective actions had been taken to prevent recurrence.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M20 was evaluated.

UFSAR Supplement. LRA Section A.2.1.11, as amended in responses dated January 13, 2014, May 5, 2014, June 30, 2014, and August 29, 2014, provides the UFSAR supplement for the Open-Cycle Cooling Water System Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the UFSAR supplement description associated with coating integrity is consistent with staff's recommended actions to manage loss of coating integrity as delineated in SER Section 3.0.3.3.1. The staff also noticed that the applicant will implement the enhancements to the Open-Cycle Cooling Water System Program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Open-Cycle Cooling Water System Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Closed Treated Water Systems

Summary of Technical Information in the Application. LRA Section B.2.1.12 describes the existing Closed Treated Water Systems Program as consistent, with enhancements, with GALL Report AMP XI.M21A, "Closed Treated Water Systems." The LRA states that the AMP manages loss of material, reduction of heat transfer, and cracking in metallic piping, piping components, piping elements, tanks, and heat exchangers exposed to a closed treated water environment. The LRA also states that the AMP proposes to manage these aging effects through (a) nitrite-based and glycol-based water treatments to minimize corrosion, (b) chemical testing of the water to ensure that the water chemistry is maintained within guidelines, and (c) inspections for corrosion and cracking.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M21A.

For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The “detection of aging effects” program element in GALL Report AMP XI.M21A recommends that visual inspections to detect aging effects are conducted whenever the system boundary is opened. However, during its audit, the staff found that the applicant’s Closed Treated Water Systems Program does not specifically include inspections capable of detecting loss of material and cracking whenever the system boundary is opened. Rather, for these opportunistic inspections, the applicant’s program credits the general practices at the site, where personnel are trained to identify conditions and, if appropriate, enter those conditions into the CAP. The staff noticed that this practice does not include specific inspection and personnel qualification procedures to ensure that loss of material and cracking can be detected. By letter dated February 6, 2014, the staff issued RAI B.2.1.12-1 requesting that the applicant provide a technical justification to demonstrate that the aging effects will be adequately managed despite this exception to the GALL Report guidance, or alternatively, provide an enhancement to the program to include these opportunistic inspections.

In its response dated February 27, 2014, the applicant stated that existing station procedures require a general visual inspection of internal surfaces of components when the systems are opened. The applicant also stated that personnel performing the inspections are qualified to Exelon job qualifications and in accordance with the Institute of Nuclear Power Operations (INPO) National Academy for Nuclear Training accredited training program. The staff noticed that the applicant’s response did not include details of the Exelon job qualifications, INPO training, or station procedures that would demonstrate that personnel performing inspections are sufficiently qualified and will be inspecting for parameters capable of identifying the applicable aging effects. By letter dated May 19, 2014, the staff issued RAI B.2.1.12-1a to request these details.

In its response dated June 9, 2014, the applicant stated that the personnel who will perform the inspections are trained on the various methods of corrosion control in the closed-cooling water systems and are knowledgeable about the expected conditions of the piping and components. To ensure personnel are familiar with and capable of detecting various forms of age-related degradation, the applicant described various aspects of the training program, including modules on common failure mechanisms and NDE techniques, as well as familiarization with color photographs of corrosion types that could be encountered. The applicant also stated that procedures require maintenance personnel to enter any inspection results that reveal more than the expected amount of age-related degradation into the CAP. Due to the chemistry controls in the closed-cooling water systems, the applicant does not expect any age-related degradation. Therefore, applicant personnel will document any detectable loss of material or cracking identified during opportunistic visual inspections, and the condition will be evaluated in the CAP, including the need for additional inspections to determine the extent of the degradation.

The staff notes that, while not explicitly stated by the applicant, the response describes the program’s acceptance criteria as not permitting any degradation, which is consistent with SRP-LR Section A.1.2.3.6, “Acceptance Criteria,” for maintaining the intended function under all CLB design loads. The staff finds the applicant’s response acceptable because the training details and inspection acceptance criteria described above provide reasonable assurance that (a) the visual inspections performed by personnel during maintenance activities are capable of detecting conditions indicative of material degradation and (b) any evidence of age-related degradation will be evaluated by the CAP. The staff’s concern described in RAIs B.2.1.12-1 and B.2.1.12-1a is resolved.

The staff also reviewed the portions of the “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.12 includes an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated that visual and nondestructive examinations will be conducted on a representative sample of piping and components at an interval not to exceed once in 10 years. The staff noticed that GALL Report AMP XI.M21A recommends inspecting a representative sample of piping and components at an interval not to exceed once in 10 years. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because when it is implemented it will make the program consistent with the GALL Report AMP. The staff noticed that GALL Report AMP XI.M21A also includes opportunistic inspections whenever the system boundary is opened, and that aspect of the program is documented above in the discussion of RAI B.2.1.12-1.

Enhancement 2. LRA Section B.2.1.12 includes an enhancement to the "scope of program," "preventive actions," "parameters monitored or inspected," and "monitoring and trending" program elements. The applicant stated that the program will include periodic sampling, analysis, and trending of water chemistry for the essential service water makeup pump engine glycol-based jacket water system. The staff noticed that LRA Section B.2.1.12 also states that water chemistry sampling and analysis is performed consistent with EPRI Report 1007820, "Closed Cooling Water Chemistry Guideline, Revision 1." The staff noticed that GALL Report AMP XI.M21A states that the program monitors water chemistry in accordance with EPRI 1007820 to ensure that the water treatment program is effective. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP XI.M21A and finds it acceptable because when it is implemented it will make the program consistent with the GALL Report AMP.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.12-1 and B.2.1.12-1a, the staff finds that program elements 1 through 3, 5, and 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M21A. In addition, the staff reviewed the enhancements associated with the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.12 summarizes OE related to the Closed Treated Water Systems Program. In 2009, eddy current testing on a Byron Station primary containment chiller identified an evaporator tube with wall thinning greater than 40 percent, which is the threshold for preventive tube plugging. The applicant stated that the number of tubes needing plugging has dropped over the past several years after it was recognized that improper layups were causing the tube wall thinning. The current closed treated water program monitors the chiller water systems to ensure that chemistry parameters are appropriately maintained. Eddy current testing of the tubes is performed to identify at-risk tubes in the containment chiller and to plug them prior to failure. In 2008, the applicant identified low nitrite concentrations in the station heat system at Byron Station. The immediate corrective action was to make a chemical addition to exit all action levels for chemistry control. Followup corrective actions included the identification and repair of the leak responsible for the low nitrite levels in the fuel handling building train shed station heat pump seal. From 2009 to 2012, Braidwood Station identified jacket water leaks in the emergency diesel generator (EDG) fuel oil coolers. The leaks were associated with sacrificial anodes, which leaked by design when the anodes were consumed. The anodes were cleaned and reinstalled or replaced; however, the leaks recurred. The station implemented an adverse condition monitoring plan to track and trend the leakage until the coolers were ultimately modified to no longer use the anodes.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M21A was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.12 provides the UFSAR supplement for the Closed Treated Water Systems Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's Closed Treated Water Systems program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 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 Report AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The LRA states that the AMP proposes to manage loss of material due to corrosion for structural components and bolting, loss of material due to wear and corrosion for rails, and loss of preload for bolting. The LRA also states that visual inspection methods are effective in detecting loss of material and evidence of loss of preload, and the inspection frequencies are adequate to prevent significant age-related degradation from occurring.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M23.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," 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.2.1.13 includes an enhancement to the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements. The applicant stated that inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for evidence of loss of preload will be performed consistently. The program description states that this will be accomplished by ensuring the program's implementing documents consistently include these activities. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because when it is implemented it will make the program consistent with the GALL Report AMP.

Enhancement 2. LRA Section B.2.1.13 includes an enhancement to the "detection of aging effects" program element. The applicant stated that periodic inspections will be performed on all cranes, hoists, monorails, and rigging beams within the scope of license renewal, including those that are infrequently in use. The staff noticed that the program's inspection frequencies are consistent with the ASME B30 series of standards, as recommended by the GALL Report. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because when it is implemented it will make the program consistent with the GALL Report AMP.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M23. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.13 summarizes OE related to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. During an inspection in 2003, loose bolting was discovered during routine periodic inspections of a refueling cavity maintenance crane. At that time, the applicant entered the condition into the CAP, and the bolts were retightened prior to use of the crane. Preventive maintenance activities were then reviewed to ensure that inspections were planned for other cranes prior to use. The LRA also describes reviews of over 1,500 Byron Station corrective action reports and 900 Braidwood Station corrective actions reports since 2001. Both of which did not identify any history of significant loss of material due to corrosion in structural members of cranes and hoists, loss of material due to wear in the rail system, or loss of preload of associated bolting (with the exception of the single instance described above).

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M23 was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.13 provides the UFSAR supplement for the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its 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 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 Compressed Air Monitoring

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.14 describes the existing Compressed Air Monitoring Program as consistent, with an exception and an enhancement, with GALL Report AMP XI.M24, "Compressed Air Monitoring." The LRA states that the AMP addresses loss of material of piping, piping components, and piping elements in the compressed air systems in a condensation environment. The LRA also states that the AMP proposes to manage this aging effect in accordance with BBS's response to NRC GL 88-14, "Instrument Air Supply Problems," through monitoring of moisture content and contaminants and periodic inspections of select compressed air system component internal surfaces for indications of loss of material.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M24.

The staff also reviewed the portions of the "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with the exception and enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancement follows.

Exception. LRA Section B.2.1.14 includes an exception to the "monitoring and trending" program element. The applicant stated that its instrument air system dryer outlet dew points are continuously monitored utilizing in-line detectors with automatic alarms in the main control room; in addition, quarterly samples are taken from representative locations that are analyzed and trended for dew point as well as particulates and hydrocarbons. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M24 and finds it acceptable because the applicant will continuously monitor the dew point, which will alert the applicant to any potential moisture within the system. Additionally, taking quarterly air samples for dew point and contaminants is consistent with the guidance in ASME OM-S/G-1998, Part 17.

Enhancement. LRA Section B.2.1.14 includes an enhancement to the "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that prior to the period of extended operation it will enhance its program to inspect critical component internal surfaces for signs of loss of material due to corrosion and document deficiencies in CAP. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M24 and finds it acceptable because when it is implemented these program elements will be consistent with the guidance in the GALL Report AMP.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M24. The staff also reviewed the exception associated with the "monitoring and trending" program element, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancement associated with the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.14 summarizes OE related to the Compressed Air Monitoring Program.

Byron Station. In December 2007, during rounds, operators identified that the differential pressure across the prefilter of the Unit 1 Air Dryer exceeded the weekly surveillance limit of 5 psid by 1 psid. The issue was communicated to supervision and entered into the CAP. A work order request was generated and the filters were replaced.

Also in December 2007, air quality testing was performed with unsatisfactory results for dew point temperatures with the Unit Common and Unit 2 air dryers in service. Because recent dryer test results were acceptable, it was thought that the unsatisfactory results were due to a measurement error and, therefore, a retest was requested. The issue was placed into the CAP, and retesting was tracked. Subsequent testing found header sample points, as well as the dryers, all reading less than −80 °F (−60 °C), which was well within the acceptable range.

Braidwood Station. In June 2009, quarterly air quality testing was performed on air samples taken from the instrument air header and air dryer discharge resulting in unsatisfactory results for dew point temperatures. Acceptance criteria of less than −25 °F (−32 °C) was not met at the outlet of the Unit 2 instrument air dryer (−22 °F (−30 °C)) nor at header locations in the auxiliary building (−25 °F) nor at the turbine building (−25 °F). An elevated particulate count was also noted in the turbine building instrument air header. Engineering requested that an extended blowdown of the system be performed to remove the particulates, along with a change of desiccant to improve the dew point temperatures during the upcoming Unit 2 dryer maintenance window.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M24 was evaluated.

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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to enhance the program to include internal inspections of critical components prior to entering the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program

Conclusion. On the basis of its audit and its review of the applicant's Compressed Air Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancement and confirmed that its implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Fire Protection

Summary of Technical Information in the Application. LRA Section B.2.1.15 describes the existing Fire Protection Program as consistent, with enhancements, with GALL Report AMP XI.M26, "Fire Protection." The LRA states that the program manages loss of material through periodic functional testing and visual inspection of components performing a fire barrier intended function associated with the halon and low-pressure carbon dioxide (CO_2) fire suppression systems, and periodic visual inspections of fire barrier walls, ceilings, and floors separating safety-related fire areas or separating portions of redundant systems important to safe shutdown within a fire area for loss of material, cracking, and spalling. The program includes visual inspections of not less than 10 percent of each type of penetration seal for signs of degradation such as cracking, hardening, loss of bond, loss of material, loss of strength, and physical damage at least once per 18 months. The program also includes visual inspections of all fire dampers that penetrate fire barriers within the scope of the program at least once per 18 months. Lastly, the program includes periodic visual and functional testing of fire doors to ensure their operability at least once per 6 months.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M26.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.15 includes an enhancement to the "scope of program," program element. The applicant stated that it will include visual inspections of the earthen berm enclosing the outdoor fuel oil storage tanks for signs of age-related degradation such as loss of material and loss of form. GALL Report AMP XI.M26 recommends that the effects of aging on components that serve a fire barrier function be managed. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M26 and finds it acceptable because when it is implemented it will ensure that visual inspections of the earthen berm will be performed consistent with the recommendations in the GALL Report.

Enhancement 2. LRA Section B.2.1.15 includes an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that it will provide additional inspection guidance to identify age-related degradation of fire barrier walls, ceilings, and floors or aging effects such as cracking, spalling, and loss of material. GALL Report AMP XI.M26 recommends that visual inspections of the fire barrier walls, ceilings, and floors and other fire barrier materials to detect any sign of degradation, such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates be conducted. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because when it is implemented it will ensure that visual inspections of fire barriers are performed consistent with the recommendations in the GALL Report.

Enhancement 3. LRA Section B.2.1.15 includes an enhancement to the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that it will include visual inspection of halon and low-pressure CO_2 fire suppression system piping and component external surfaces for signs of corrosion or other age-related degradation. GALL Report AMP XI.M26 recommends that visual inspections of the halon/CO_2 fire suppression system be performed to detect any sign of corrosion. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X/XI.LNN and finds it acceptable because when it is implemented it will ensure that visual inspections of halon/CO_2 systems are performed consistent with the recommendations in the GALL Report.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M26. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.15 summarizes operating experience related to the Fire Protection. A summary of the OE for each station is provided below.

Byron Station. In February 2012, an 18-in. by 20-in. section of Thermafiber insulation protecting a beam was damaged in the Unit 2 Auxiliary Building. The foil enclosing the section of Thermafiber insulation was also removed and damaged. Engineering performed an evaluation and determined that the fireproofing was degraded but operable and needed to be repaired. Engineering personnel also performed a walkdown of the area and identified an exposed reinforcing plate on an otherwise fireproofed beam. The beam was declared inoperable, and an hourly firewatch was initiated. The fireproofing for these two locations was repaired to acceptable conditions in accordance with applicable design documents.

In September 2011, during the 100-percent inspection of all technical requirements manual fire doors, minor deficiencies were identified on several of the 175 fire doors inspected. The deficiencies included improper operation of the latching mechanism, interference in the ability to properly close and seal, a degraded hinge, loose and missing parts, and improper alignment of a door in a frame. All of the identified deficiencies were evaluated by site personnel in accordance with plant procedures, and they determined that there were no operability issues. All required repairs were performed to correct the identified deficiencies to prevent any further degradation that could affect operability.

In December 2011, the 18-month visual inspection surveillance of 10 percent of the fire barrier penetrations was completed. As part of this inspection, 10 percent of each type of fire seals was inspected. Each of the inspected fire seals met the acceptance criteria, and no seal failures were identified. However, two fire seals were identified as having minor deficiencies, (i.e., minor chipping, less than one-fourth inch, and some surface cracking). The degraded conditions were evaluated as acceptable for operability and entered into the CAP for repair to prevent any further degradation. Since no seal failures were identified, the inspection scope was not increased.

Braidwood Station. As part of the 18-month surveillance of all fire rated assemblies, a visual inspection of the unit-common fire rated assemblies was completed in February 2010. During the completion of this surveillance, minor deficiencies (due to both age-related and non-age-related degradation) in the fire rated assemblies were identified, including degradation of Pyrocrete fireproofing (due to cracking and voids) and areas with missing grout or fireproofing. The degraded conditions were entered into the CAP, and plant barrier impairment tags were issued, as required. Degraded fire barriers were repaired in accordance with governing design documents.

As part of the 18-month surveillance of all fire dampers installed in fire assemblies, a visual inspection of the auxiliary building ventilation system nonelectrothermal link fire dampers was completed in March 2011. No signs of age-related degradation were identified during the performance of these inspections, and the material condition of all 43 fire dampers was found to be satisfactory. However, during the performance of this inspection it was identified that the fan blade assembly had fallen off the motor shaft of the auxiliary building control panel room vent fan. The degraded condition was entered into the CAP for repair.

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 OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. During its review, the staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M26 was evaluated.

UFSAR Supplement. LRA Section A.2.1.15 provides the UFSAR supplement for the Fire Protection Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to entering the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Fire Protection Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 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 Report AMP XI.M27, "Fire Water System." The LRA states that the AMP addresses carbon steel, copper-alloy, ductile cast iron, galvanized steel, gray cast iron, and SS materials in the water-based fire protection system and manages components such as sprinklers, fittings, valves, hydrants, hose stations, standpipes, tanks, pumps, and piping (aboveground and buried) exposed to raw water and outdoor air for loss of material. As amended by letters dated January 13, 2014, March 13, 2014, and June 30, 2014, the program also manages loss of coating integrity and flow blockage due to fouling. The LRA further states that the AMP proposes to manage these aging effects through system pressure monitoring, system header flushing, buried ring header flow testing, pump performance testing, hydrant full flow flushing and full flow verification, sprinkler and deluge system flushing and flow testing, hydrostatic testing, sprinkler head testing, and inspection activities. The program includes an enhancement to perform additional "preventive actions" only at Byron where chemical additions will be used to prevent or minimize MIC. The LRA states that the fire water system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions are initiated.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M27 as revised in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation," which was issued subsequent to the submittal of the LRA.

For the "parameters monitored or inspected" and "detection of aging effects" program elements, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

Information Notice (IN) 2013-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction," addresses blockage in fire sprinkler piping due to accumulation of corrosion products. This IN and the review of several LRAs caused the staff to reconsider the current approach in GALL Report AMP XI.M27, "Fire Water System," resulting, in part, in the issuance of LR-ISG-2012-02. In addition, during its review of plant-specific OE, the staff identified instances of potential flow blockage in fire water systems at Byron. By letter dated February 18, 2014, the staff issued RAI B.2.1.16-1 requesting that the applicant respond to items (1) – (4) below, which correlate to information contained in AMP XI.M27 as revised in LR-ISG-2012-02. The staff determined that RAI B.2.1.16-1 items (1) and (4) include tests and inspections capable of detecting internal corrosion and flow blockage in fire water systems and therefore will address the OE related to potential flow blockage issues identified at Byron. The applicant responded by letter dated March 13, 2014.

1. The staff requested the applicant confirm that the current Fire Water System program conducts inspections and tests related to loss of material and flow blockage of associated components in accordance with the guidance in LR-ISG-2012-02, AMP XI.M27 Table 4a, "Fire Water System Inspection and Testing Recommendations." The staff noticed that RAI B.2.1.16-1 was developed before the final version of LR-ISG-2012-02 had been issued. Consequently, the RAI includes a table with minor editorial differences from the one cited in LR-ISG-2012-02 AMP XI.M27 Table 4a, and it also did not include the water storage tank recommendations because neither site has fire water storage tanks.

   The applicant addressed each of the recommended tests or inspections specified in Table 4a, which correlate to various sections of National Fire Protection Association (NFPA) 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," as follows:

   Sprinkler Inspections. The applicant stated that visual inspections are conducted at least annually and check for age-related degradation (e.g., corrosion) or indications of leakage.

   The staff finds the applicant's proposal acceptable because annual sprinkler inspections are consistent with LR-ISG-2012-02 AMP XI.M27 Table 4a.

   Sprinkler Testing. The applicant stated that Enhancement No. 1 addresses sprinkler testing. The staff's evaluation of Enhancement No. 1 is documented below.

   Flow Tests. The applicant stated that flow testing, as specified in NFPA 25 Section 6.3.1, is not performed at the hydraulically most remote hose connection of each zone of the automatic standpipe system. However, the program will be enhanced (Enhancement No. 3) to perform main drain testing annually, in accordance with NFPA 25 Section 13.2.5, which will ensure flow blockage in the fire water headers does not occur. In addition, the program includes flushing and flow verification at each hose station at least once every 5 years. The applicant concluded that because the hose stations are supplied by the same headers as the sprinkler and deluge systems, flow verification at each hose station, in conjunction with main drain testing, provides reasonable assurance that flow blockage does not occur.

The staff finds the applicant's exception to NFPA 25 Section 6.3.1 acceptable because conducting annual main drain tests at each system riser, as specified in NFPA 25 Section 13.2.5, and flushing and flow verification at every hose station once every 5 years provide sufficient insight to identify changes in the internal conditions of the fire water supply piping that are indicative of potential flow blockage.

Underground and Exposed Piping Flow Tests. The applicant stated that flow testing of the underground fire water header at flow rates representative of those expected during a fire is performed on a 3-year frequency to determine the internal condition of the piping.

The staff finds the applicant's proposal acceptable because the underground portions of the piping are flow tested more frequently than that stated in NFPA 25. In addition, the main drain testing and hose station flow verification described above provide sufficient insight to identify changes in the internal conditions of the fire water supply piping that are indicative of potential flow blockage.

Hydrants. The applicant stated that flushing of fire hydrants is performed annually to verify the hydrants are functioning properly and to prevent the buildup of sediment in the header.

The staff finds the applicant's proposal acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27 Table 4a.

Suction Screens. The applicant stated that the suction screens for the intake bays are not in-scope for license renewal and inspections of these screens would not provide an indication of the condition of the internal surface of components within the scope of the Fire Water System Program. The staff noticed that in its response to RAI 2.3.3.12-4 dated July 18, 2014, the applicant added the Braidwood intake bay travelling screens to the scope of license renewal. The Byron intake bays are not equipped with travelling screens. The staff's evaluation of the response to RAI 2.3.3.12-4 is documented in SER Section 2.3.3.12.2.

The staff noticed that the response to RAI 2.3.3.12-4 states that SS suction screens are installed on the fire water pumps, the Byron fire pumps take suction from the circulating water pump house intake bay, and the Braidwood fire pumps take suction from the lake screen structure intake bays.

The staff finds the applicant's proposal that the suction screens for the intake bays, inclusive of the travelling screens and fire pump suction screens, would not provide an indication of the condition of the internal surface of components of the fire water system acceptable because, although debris on the screens would be indicative of debris conditions in the intake bays (the fire water makeup source), it would not be indicative of aging effects associated with loss of material and flow blockage for in-scope fire water system components.

Main Drain Tests. The applicant stated that Enhancement No. 3 addresses main drain tests. The staff's evaluation of Enhancement No. 3 is documented below.

Deluge Valves. The applicant stated that full flow testing of deluge systems for transformers will be performed at least once every 3 years. The applicant also stated that the Fire Water System Program at Byron will be enhanced (Enhancement No. 4) to conduct air flow testing of all other deluge systems every 3 years. The Braidwood Fire Water System Program includes air flow testing of all other deluge systems every 3 years.

The staff noticed that NFPA 25 Sections 13.4.3.2.2.4 and 13.4.3.2.2.5(A) allow a surveillance frequency of every 3 years and the use of air as a test medium. The interval between tests is longer than that recommended interval in Table 4a footnote 5; however, the staff finds the applicant's proposal acceptable because it is consistent with the maximum interval for testing and test medium allowed in NFPA 25.

Strainers. The applicant stated that individual nozzle strainers are not installed in the fire water system. The applicant also stated that mainline strainers for the water spray fixed systems would be inspected at least once every 6 years and only experience flow during automatic system actuation and periodic flow testing or flushing. The applicant reviewed the more than 40 inspections for the water spray fixed system mainline strainers conducted during the last 10 years and did not identify any instances of flow blockage. The applicant also stated that any potential flow blockage of the strainers would be identified during periodic flow testing of the system because the strainers are located within the flow path that is tested for obstruction. Although currently included at Byron, the Fire Water System Program will be enhanced (Enhancement No. 5) for Braidwood to require strainer inspections when the system is reset after automatic system actuation.

The staff noticed that NFPA 25 Section 10.2.1.7 states that mainline strainers shall be inspected every 5 years. The staff finds the applicant's proposal acceptable because conducting the inspections every 6 years, in lieu of 5 years, is sufficient given that 10 years of inspections identified no instances of flow blockage, and flow testing could provide an indication of accumulation of debris (e.g., corrosion products) on the screens.

Operation Test. The applicant stated that water discharge pattern for nozzles on the deluge systems for the transformers will be observed for the effects of plugged nozzles during full flow testing performed on a 3-year frequency. Inspections for nozzle obstructions will be conducted during air flow testing of all other deluge systems.

The staff noticed that the 3-year frequency exceeds that recommended in LR-ISG-2012-02 AMP XI.M27 Table 4a; however, NFPA 25 Sections 13.4.3.2.2.4 and 13.4.3.2.2.5(A) allow a surveillance frequency of every 3 years and the use of air as a test medium. The staff finds the applicant's proposal acceptable because nozzle blockage and obstructions are best detected during flow testing as described above in *Deluge Valve* testing.

Foam Water System Strainers. The applicant stated that individual strainer nozzles are not installed in the foam water sprinkler system. The applicant also stated that mainline strainers for the foam fire suppression systems are inspected at least once every 6 years and only experience flow during automatic system actuation and periodic flow testing or flushing. Also, the applicant reviewed the more than 50 inspections for the foam fire suppression systems conducted during the last 10 years and did not identify any instances of flow blockage. Although currently included at Byron, for Braidwood the Fire Water System Program will be enhanced (Enhancement No. 5) to require strainer inspections when the system is reset after automatic system actuation.

The staff noticed that NFPA 25 Sections 10.2.1.7 and 11.2.7.1 require mainline strainers for foam water systems to be inspected every 5 years. The staff finds the applicant's proposal acceptable because conducting the inspections every 6 years, in lieu of 5 years, is sufficient given that 10 years of inspections identified no instances of flow blockage.

<u>Foam Water System Operational Test Discharge Patterns</u>. The applicant stated that air flow testing of the foam fire suppression spray nozzles is conducted every 3 years to ensure that they are not obstructed and the testing frequency for individual foam fire suppression subsystems is based on prior testing results.

The staff noticed that the 3-year frequency exceeds that recommended in LR-ISG-2012-02 AMP XI.M27 Table 4a; however, NFPA 25 Sections 13.4.3.2.2.4 and 13.4.3.2.2.5(A) allow a surveillance frequency of every 3 years and the use of air as a test medium. The staff finds the applicant's proposal acceptable because it is consistent with the maximum interval for testing and test medium allowed in NFPA 25, and plant-specific OE is used to determine if individual suppression subsystems are tested more frequently.

<u>Foam Water System Storage Tanks</u>. The applicant stated that the program will be enhanced (Enhancement No. 6) to conduct the internal visual inspections of the foam concentrate tank every 10 years instead of the current program frequency of every 15 years. The staff's evaluation of Enhancement No. 6 is documented below.

<u>Obstruction Internal Inspections of Piping</u>. The applicant stated that the Fire Water System program will be enhanced (Enhancement No. 7) to include nondestructive examinations (NDE) capable of detecting internal flow blockage. The staff's evaluation of Enhancement No. 7 is documented herein.

2. The staff requested that the applicant state the bases for why these measurements will provide reasonable assurance that the intended functions of in-scope fire water system components will be maintained consistent with the CLB for the period of extended operation if wall thickness evaluations will be used in lieu of conducting flow tests or internal visual examinations.

   The applicant stated that flow testing or inspections for flow blockage will be performed as described in response to Request 1 (discussed above), and wall thickness evaluations will be performed to ensure that minimum wall thickness will be maintained. The applicant revised LRA Section B.2.1.16, "Fire Water System" to clarify that wall thickness evaluations will not be used in lieu of conducting flow tests or inspections for flow blockage.

   The staff finds the applicant's response acceptable because the tests and inspections described above are sufficient to detect potential loss of material and flow blockage for passive long-lived in-scope components in the fire water system, and the program was revised to clarify that wall thickness evaluations will not be used in lieu of conducting flow tests or inspections for flow blockage.

3. The staff requested that the applicant either confirm that followup volumetric examinations will be conducted whenever internal visual inspections detect surface irregularities indicative of material loss below nominal wall thickness, or provide the bases for why the visual inspection alone will provide reasonable assurance that the intended functions of in-scope fire water system components will be maintained consistent with the CLB for the period of extended operation.

   The applicant stated that reasonable assurance for managing loss of material in fire water system piping is provided through periodic volumetric examinations, flow testing, leakage testing, and external visual inspections looking for indications of system leakage. The applicant also stated that the internal visual inspections are primarily intended to detect flow blockage; however, the program requires “surface irregularities indicative of significant loss of material” identified during these visual inspections to be documented and evaluated as part of the corrective action program.

The staff acknowledges that the program will manage loss of material by conducting periodic volumetric examinations, inspecting for leakage, and evaluating the results of internal visual examinations. However, because of the applicant’s wording “surface irregularities indicative of significant loss of material,” it was not clear to the staff that all surface irregularities, including loss of material below nominal wall thickness, would be documented in the corrective action program for appropriate evaluation. By letter dated May 21, 2014, the staff issued RAI B.2.1.16-1b requesting that the applicant state how it would disposition an internal visual examination that revealed loss of material below nominal wall thickness.

In its response dated June 16, 2014, the applicant stated that the program will not document all surface irregularities indicative of wall loss below nominal pipe wall thickness that are identified by internal visual inspections. The applicant explained that new piping is supplied at nominal wall thickness and, since uniform loss of material is expected to occur in the raw water environment for fire water system components, any loss of material would be indicative of wall loss below nominal. The applicant stated that identification of surface irregularities indicative of wall loss below nominal is an overly restrictive threshold for requiring entry of the condition into the CAP and followup volumetric inspections. The applicant clarified that visual inspection results will be entered into the corrective action program if unexpected levels of degradation are identified and defined unexpected levels of degradation to include “excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer.” The applicant also stated that the program relies on the CAP to determine if followup volumetric inspections are warranted.

The staff determined that the RAI response outlines the justification for an exception to conducting followup volumetric examinations as provided in LR-ISG-2012-02 AMP XI.M27. The staff agrees that wall loss below the nominal wall thickness value is an overly restrictive threshold and that using an “unexpected level of degradation” is an appropriate acceptance criterion for entering an inspection finding in the corrective action program. However, the response does not specify the action to be taken, as discussed in SRP-LR Section A.1.2.3.7, “Corrective Actions,” when acceptance criteria are not met, (i.e., when a volumetric examination will be performed to ensure that minimum design wall thickness is maintained). By letter dated August 4, 2014, the staff issued RAI B.2.1.16-1c requesting that the applicant either provide additional details regarding the periodic volumetric examinations to be performed by the Fire Water System Program, or state what indications of unexpected degradation will result in a followup wall thickness examination for opportunistic internal visual inspections.

In its response dated August 29, 2014, the applicant stated that the Fire Water System Program will rely on periodic volumetric examinations instead of opportunistic followup wall thickness examinations. The applicant enhanced the program (Enhancement No. 15) to include a minimum of 25 volumetric examinations every 10 years at both Byron and Braidwood. The staff noticed that, as described in Enhancement No. 9, the applicant had enhanced the program at Byron to include 30 volumetric inspections of the fire water system every 3 years. The applicant provided criteria for reducing the number of inspections to 25 every 10 years as described below in Enhancement No. 9 and in the response to RAI B.2.1.16-2. The applicant also stated that existing procedures require that inspection location selections for raw water systems incorporate risk insights based on susceptibility to loss of material and the consequences of leakage. The applicant stated that existing procedures also require that raw water sample sizes be increased as follows: (a) four additional inspections if wall loss of greater than 50 percent of nominal wall thickness is detected; (b) two additional inspections if wall loss of 30 percent to 50 percent of nominal wall thickness is detected and calculated remaining life is less than two years; and (c) no additional inspections if wall loss less than 30 percent of nominal wall thickness is detected. The applicant revised LRA Sections A.2.1.16 and B.2.1.16 to reflect the above changes.

The staff finds the applicant's response acceptable because a sample size of 25 risk-ranked inspections is consistent with existing sample-based programs such as GALL Report AMP XI.M38 and the applicant has specified increases in inspection sample size based on inspection results. The increased inspections, when required, will provide the applicant with additional insights into the breadth of loss of material in the system. The staff's evaluation of the criteria for reducing the number of plant-specific inspections at Byron is documented in the response to RAI B.2.1.16-2, below.

4. The staff requested that the applicant state the inspection method to ensure that fouling is not occurring, the parameters to be inspected, when inspections will commence, the frequency of subsequent inspections, the extent of inspections, and acceptance criteria for portions of the water-based fire protection system that are designed to be normally dry but are periodically subjected to flow and are not configured to completely drain.

   The applicant stated that flow testing or visual inspections of the internal surface of portions of the system that meet the above criteria will be performed to ensure flow blockage is not occurring. In addition, volumetric examinations will be performed to verify that significant loss of material is not occurring. Inspections and testing will commence 5 years prior to the period of extended operation and will be conducted on a 5-year frequency thereafter in 100 percent of the applicable portions of the water-based fire protection system. Volumetric examinations will be performed on 20 percent of the applicable portions of the water based fire protection system. The 20 percent of the piping that is inspected in each 5-year interval will be in different locations than previously inspected. Reduction in flow such that the system is not capable of performing its intended function and wall thickness measurements below nominal wall thickness will be entered into the corrective action program.

   The staff noticed that the applicant incorporated the above into changes to LRA Sections A.2.1.16 and B.2.1.16, and Commitment No. 16. The staff finds the applicant's response acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

<u>*Enhancement 1*</u>. LRA Section B.2.1.16 includes an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated it will replace sprinkler heads with 50 years or more service or test the sprinkler heads in accordance with NFPA 25. This testing will be performed at the 50-year inservice date and every 10 years thereafter. The staff reviewed this enhancement against the corresponding program elements

in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because the proposed timing of the sprinkler head replacement or testing will be consistent with AMP XI.M27.

Enhancement 2. LRA Section B.2.1.16 includes an enhancement to the "preventive actions" program element. The applicant stated that Byron will add chemicals to the fire water system during system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize MIC. Based on its review of plant-specific OE at BBS, the staff determined that the fire water system at Byron has experienced extensive through-wall MIC leaks; whereas, at Braidwood this has not occurred and sampling has not detected evidence of biological growth. The staff finds this enhancement acceptable because, when implemented, chemical treatments are known to reduce biological activity and therefore the occurrence of MIC.

Enhancement 3. LRA Section B.2.1.16, as modified by response dated March 13, 2014, includes an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated that it will perform main drain tests annually, in accordance with NFPA 25 Section 13.2.5. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because when main drain tests, accompanied by other inspections and tests as described above, provide sufficient insight relative to changes in the internal conditions of the fire water supply piping to detect potential flow blockage.

Enhancement 4. LRA Section B.2.1.16, as modified by response dated March 13, 2014, includes an enhancement to the "parameters monitored and inspected" and "detection of aging effects" program elements. The applicant stated that, at Byron, it will perform air flow testing of deluge systems that are not subject to periodic full flow testing on a 3-year frequency to verify that internal flow blockage does not occur. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, as discussed above for deluge testing, it is consistent with the maximum interval for testing and test medium allowed in NFPA 25.

Enhancement 5. LRA Section B.2.1.16, as modified by response dated March 13, 2014, includes an enhancement to the "detection of aging effects" program element. The applicant stated that, at Braidwood, it will perform inspections of fire protection system strainers when the system is reset after automatic actuation for signs of internal flow blockage. As discussed above for strainer testing, the staff noticed that this aspect is already included at Byron. The staff finds this enhancement acceptable because strainer inspections after automatic system actuation are consistent with guidance in NFPA 25.

Enhancement 6. LRA Section B.2.1.16, as modified by responses dated March 13, 2014, and June 30, 2014, includes an enhancement to the "detection of aging effects" program element. The applicant stated that it will inspect the internal surfaces of the foam concentrate tanks at least once every 10 years starting 10 years prior to the period of extended operation. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because it is consistent with AMP XI.M27, which recommends inspections of the internal surfaces of these storage tanks every 10 years.

Enhancement 7. LRA Section B.2.1.16, as modified by response dated March 13, 2014, includes an enhancement to the "detection of aging effects" program element. The applicant stated that it will perform NDE capable of detecting internal flow blockage (e.g., digital radiography) or internal visual inspections every 5 years. As discussed in response to

RAI B.2.1.16-1 for obstruction internal inspection of piping, the visual inspections will be performed by opening a flushing connection at the end of one fire main and removing a sprinkler toward the end of one sprinkler system branch line in each structure containing in-scope water-based fire suppression systems. The applicant also stated that an obstruction investigation will be performed if inspections identify internal flow blockage that could prevent the system from delivering the required flow.

The staff noticed that NFPA 25 Section 14.2.2 requires, on an alternating schedule, an internal inspection of every other wet pipe system in buildings with multiple wet pipe systems. The staff also noticed that LR-ISG-2012-02 AMP XI.M27 Table 4a, footnote 3 limits the alternative NDE methods, which are permitted by NFPA, Sections 14.2.1.1 and 14.3.2.3, to those that can ensure that flow blockage will not occur. The staff further noticed that EPRI Technical Report (TR)-102063, “Guide for the Examination of Service Water System Piping,” March 1994, Section 3.1 recommends radiography as an effective method capable of measuring the extent of occlusions or biofouling conditions; however, the enhancement states that digital radiography is an example of an NDE technique that might be used, leading the staff to conclude that other methods could be used. The staff lacked sufficient information to complete its evaluation of the applicant’s proposal because it is not clear whether there are multiple wet pipe systems in any of the structures containing in-scope fire water systems, and it does not know how other NDE techniques will be demonstrated effective at detecting flow blockage. By letter dated May 21, 2014, the staff issued RAI B.2.1.16-1a requesting that the applicant clarify the above aspects.

In its response dated June 16, 2014, the applicant stated that, since some of the structures contain multiple in-scope wet pipe fire water systems, the Fire Water System Program will be revised to inspect half of the wet pipe sprinkler systems every 5 years. The applicant also revised LRA Sections A.2.1.16 and B.2.1.16 to eliminate the use of other undefined NDE techniques by stating that inspections for internal flow blockage in the fire water system are performed by either radiographic testing or internal visual examinations.

The staff finds the applicant’s response acceptable because the frequency and extent of internal inspections is consistent with LR-ISG-2012-02 AMP XI.M27, and radiography and internal visual examinations are effective examination techniques to detect flow blockage.

Enhancement 8. LRA Section B.2.1.16, as modified by response dated March 13, 2014, includes an enhancement to the “scope of program” and “detection of aging effects” program elements. The applicant stated that it will perform augmented testing (as described above in the response to RAI B.2.1.16-1, Request No. 4) of those portions of the water-based fire protection system that are normally dry but periodically subjected to flow and cannot be drained or allow water to collect. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because when it is implemented it will be consistent with AMP XI.M27 which recommends augmented inspections beyond those required by NFPA 25 to ensure that potential corrosion product accumulation is detected.

Enhancement 9. LRA Section B.2.1.16, as modified by responses dated March 13, 2014, and August 29, 2014, includes an enhancement to the “parameters monitored or inspected” and “detection of aging effects” program elements. The applicant stated that, at Byron, it will perform a minimum of 30 volumetric examinations (i.e., radiographic or ultrasonic testing) of the fire protection system during each 3-year interval to address OE associated with through-wall leaks at Byron. By letter dated August 29, 2014, the applicant also revised this enhancement to address criteria for reducing the number of inspections being conducted every 10 years as described above in the response to RAI B.2.1.16-1c. The staff finds this enhancement acceptable as discussed below in response to RAI B.2.1.16-1c.

The staff's evaluation of Enhancement Nos. 10 through 14 is documented in SER Section 3.0.3.3.1.

Enhancement 10. LRA Section B.2.1.16, as modified by response dated June 30, 2014, includes an enhancement to the "detection of aging effects" program element. The applicant stated that inspections of internal coatings will be conducted by inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54.

Enhancement 11. LRA Section B.2.1.16, as modified by response dated June 30, 2014, includes an enhancement to the "acceptance criteria" program element. The applicant stated that, "signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program."

Enhancement 12. LRA Section B.2.1.16, as modified by response dated June 30, 2014, includes an enhancement to the "acceptance criteria" program element. The applicant stated that when peeling, blistering, or delamination is detected and the coating is not repaired or replaced, physical testing of internal coatings will be conducted, where physically possible, to confirm that the remaining coating is tightly bonded to the base metal. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54.

Enhancement 13. LRA Section B.2.1.16, as modified by response dated June 30, 2014, includes an enhancement to the "monitoring and trending," "acceptance criteria," and "corrective actions" program elements. The applicant stated that when a coated component exhibiting signs of peeling, blistering, or delamination is returned to service without repairing or replacement, an evaluation will be conducted including consideration of the potential impact on the intended function of the system due to flow blockage and loss of material.

Enhancement 14. LRA Section B.2.1.16, as modified by response dated June 30, 2014, includes an enhancement to the "monitoring and trending" program element. The applicant stated that degraded coatings exhibiting peeling, blistering, or delamination, and that will be returned to service without repair or replacement, will have an as-left condition that minimizes the potential for further degradation.

Enhancement 15. LRA Section B.2.1.16, as modified by response dated August 29, 2014, includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that it will perform a minimum of 25 volumetric examinations (i.e., radiographic or ultrasonic testing) of the fire water system piping every 10 years during the period of extended operation. The staff finds this enhancement acceptable as discussed above in response to RAI B.2.1.16-1c.

In addition, the staff noticed that in its January 13, 2014, submittal, the applicant revised LRA Sections A.2.1.16 and B.2.1.16 to state that the Fire Water System Program will be used to manage loss of coating integrity for components with internal coatings in the fire water system. In its March 13, 2014, submittal, the applicant deleted these statements with no explanation. The staff conducted a conference call with the applicant on June 10, 2014, during which it stated that the deletion was an editorial oversight that will be corrected in a subsequent submittal. By letter dated July 18, 2014, the applicant restored the wording in LRA Sections A.2.1.16 and B.2.1.16.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.16-1, B.2.1.16-1a, B.2.1.16-1b, B.2.1.16-1c, B.2.1.16-2, and 2.3.3.12-4, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M27 as modified by LR-ISG-2012-02 and the staff's recommended actions to manage loss of coating integrity as described in SER Section 3.0.3.3.1. In addition, the staff reviewed the enhancements associated with the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.16 summarizes OE related to the Fire Water System Program.

Byron Operating Experience Review. In March 2007, a common cause analysis (CCA) was performed to identify any commonalities between through-wall leaks in the site fire protection system. The CCA evaluated 14 corrective action reports related to system leakage generated between January 2002 and January 2007. The predominant cause was identified as MIC. The corrective actions included an inspection plan that consists of guided wave inspections of all water-filled system piping with followup UT performed at locations identified by the guided wave inspections to determine if replacement of piping is required. In addition, the periodic running of the fire water pumps has been scheduled during circulating water system chlorination to ensure that the water in the fire protection system is adequately chlorinated to help prevent MIC. Since the implementation of corrective actions, there has been only one through-wall leak in the system caused by MIC.

Braidwood Operating Experience Review. A review of plant-specific OE related to MIC of fire protection piping was performed. Sampling of fire water is performed to detect evidence of biological growth. A review of the sampling data over the past 10 years did not indicate any evidence of MIC in the fire protection system. In June 2011, during the performance of a run of the 0B fire pump, a sprinkler deluge valve alarm spuriously actuated. The spurious actuation was caused by plugging of a retard chamber drain line for a sprinkler system. The retard chamber assembly was disassembled and cleaned to provide for proper drainage and allow for depressurization per design.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of an RAI, as discussed below.

The corrective actions associated with the leaks that occurred in the fire water system at Byron included guided wave and UT examinations. Based on the staff's reviews, it appears that the corrective actions have been effective to date because they include chemical treatments to mitigate the spread of MIC and inspections to appropriately identify components that should be replaced. Although the program basis document states that nonintrusive inspections are performed on a representative number of locations, the staff notes that the implementing procedures for the Fire Water System Program do not specify the current process of using guided wave and UTs and do not include a minimum number of inspections to be conducted. By letter dated February 18, 2014, the staff issued RAI B.2.1.16-2 requesting that the applicant state the minimum number of locations to be inspected at the current frequency of 3 years.

In its response dated March 13, 2014, the applicant stated that the fire protection system is risk-ranked based on susceptibility of corrosion and consequences of a leak. The applicant enhanced the program (Enhancement No. 9) to perform 30 UT inspections at the Byron every 3 years. By letter dated August 29, 2014, the applicant amended the enhancement by stating that the number of volumetric examinations would be reduced to 25 inspections every 10 years if ongoing inspections did not identify wall loss greater than 50 percent in 3 or more areas during a 10-year interval.

The staff noticed that LR-ISG-2012-02 SRP-LR Section 3.3.2.2.8 establishes a threshold of three or more instances of loss of material exceeding 50 percent of the wall thickness as a threshold for classifying the applicable aging effect as recurring. The staff finds the applicant's response acceptable because 30 risk-ranked inspections every 3 years will provide adequate insights into the extent of MIC in the system when loss of material is recurring. Otherwise, when recurring loss of material is not occurring, a sample size of 25 risk-ranked inspections every 10 years is consistent with existing sample-based programs such as GALL Report AMP XI.M38. The staff's concern described in RAI B.2.1.16-2 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B.2.1.16-2, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which LR-ISG-2012-02 AMP XI.M27 was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.16, as amended by responses dated January 13, 2014; March 13, 2014; June 16, 2014, July 18, 2014, and August 29, 2014, provides the UFSAR supplement for the Fire Water System Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, as modified by LR-ISG-2012-02. The staff also noticed that the applicant committed to enhance the program as described above prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its 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. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 Aboveground Metallic Tanks

Summary of Technical Information in the Application. LRA Section B.2.1.17 describes the new Aboveground Metallic Tanks Program as consistent, with an exception, with GALL Report AMP XI.M29, "Aboveground Metallic Tanks." The LRA states that the AMP addresses the aluminum condensate storage tanks (CSTs) exposed to soil and outdoor air to manage the effects of loss of material. The AMP proposes to manage this aging effect through periodic visual inspections and tank bottom thickness measurements and through preventive measures including sealant and lagging with overlapping seams installed over the tank's insulated surfaces.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M29 as revised in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," which was issued subsequent to the submittal of the LRA.

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

The "detection of aging effects" program element in LR-ISG-2012-02 recommends that (a) a minimum of either twenty-five 1-square-foot sections of the tank's surface or 20 percent of the tank's surface should be examined, (b) the sample inspection points should be distributed in such a way that inspections occur in those areas most susceptible to degradation (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds), and (c) aluminum tanks should be inspected for loss of material and cracking. However, during its audit, the staff found that the applicant's Aboveground Metallic Tanks Program includes only 16 inspections; the CSTs have several attachments (e.g., instruments, heaters, ladders) that penetrate the insulation and jacketing that represent locations of higher susceptibility to rain water intrusion, and therefore, inspection locations should be selected accordingly. Cracking was not identified as an aging effect.

By letter dated December 13, 2013, the staff issued RAI B.2.1.17-1 requesting that the applicant state: (a) whether the locations where insulation will be removed will include locations below penetrations through the insulation and its jacketing; (b) whether the Foamglas® and fiberglass insulation contain low enough levels of chlorides and halides such that they will not result in pitting and cracking on the aluminum tank surfaces; (c) how it will be determined that the environment in the vicinity of the CSTs contains low enough levels of chlorides and halides such that pitting and cracking on the aluminum tank surfaces will not occur; (d) the basis for why 16 inspections will be sufficient to provide reasonable assurance that pitting and cracking will not result in a loss of intended function(s) during the period of extended operation; and (e) if cracking is an applicable aging effect, what inspection methods will be used to detect cracking and the acceptance criteria for cracks.

In its response dated January 13, 2014, the applicant stated that:

(a) It will revise the program to include inspections of four 1-foot square locations below penetrations where the insulation and its jacketing will be removed.

(b) Foamglas® insulation conforms to the requirements of Regulatory Guide 1.36, “Nonmetallic Thermal Insulation for Austenitic Stainless Steels,” February 1973; however, the specific brand of fiberglass insulation installed on the CSTs could not be identified. Therefore, it is assumed that leachable halide levels are above the levels described in Regulatory Guide 1.36.

(c) It will consider pitting and cracking of the aluminum tank surface as applicable aging effects.

(d) It will increase the sample size from 16 inspection locations to 25 for both tanks combined per site. It will also distribute the sample inspection points such that inspections will occur on the tank dome, sides, near the bottom, and at points below penetrations where equipment penetrates the insulation.

(e) It will revise the program to include a liquid penetrant examination to detect cracking, and the acceptance criteria shall be in accordance with Appendix 8 of the 2013 ASME Boiler and Pressure Vessel Code, Section VIII.

The applicant revised LRA Sections A.2.1.17, B.2.1.17, and Commitment No. 17, accordingly.

The staff finds the applicant’s response acceptable because the applicant will remove insulation and inspect the tank surfaces at locations that are susceptible to leakage past the insulation jacketing; the applicant will conduct an appropriate number of inspections to detect loss of material and cracking, which is consistent with LR-ISG-2012-02; and the applicant will revise its program to include surface examinations that are capable of detecting cracking. The staff’s concern described in RAI B.2.1.17-1 is resolved.

The “scope of program” and “detection of aging effects” program elements in LR-ISG-2012-02 recommend that: (a) indoor large-volume storage tanks designed to internal pressures approximating atmospheric pressure and exposed internally to water should be included within the scope of the Aboveground Metallic Tanks program; and (b) periodic inspections should be conducted on the tank’s bottom surface (i.e., each 10-year period starting 10 years prior to the period of extended operation) unless there is a basis for conducting a one-time inspection. However, during its audit, the staff could not conclude that there were not any indoor tanks meeting the above criteria and noticed that the applicant had proposed to conduct tank bottom ultrasonic inspections within 5 years prior to entering the period of extended operation, between years 5 and 10 of the period of extended operation, and whenever a tank is drained.

By letter dated December 13, 2013, the staff issued RAI B.2.1.17-2 requesting that the applicant state: (a) If there are any in-scope indoor welded storage tanks that meet all of the above criteria, and (b) the basis for why conducting tank bottom ultrasonic inspections within 5 years prior to entering the period of extended operation, between years 5 and 10 of the period of extended operation, and whenever a tank is drained is sufficient to provide reasonable assurance that the tank’s CLB intended function(s) will be met throughout the period of extended operation.

In its response dated January 13, 2014, the applicant stated that:

(a) There are no in-scope indoor welded storage tanks that meet all the criteria in LR-ISG-2012-02, and therefore, no additional tanks are included within the scope of the Aboveground Metallic Tanks program.

(b) It has revised the program to conduct a one-time inspection of a CST bottom at each station within the 5-year period prior to the period of extended operation. The applicant also stated that commencing 5 years prior to the period of extended operation and during the period of extended operation, the cathodic protection provided to the CST bottoms will be verified to meet the availability (i.e., at least 85 percent) and effectiveness (i.e., at least 80 percent) acceptance criteria in Table 4c, footnotes 3.ii and 3.iii, respectively of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks.'"

The staff finds the applicant's response acceptable because:

(a) The applicant did not identify any indoor welded storage tanks that meet all the criteria in LR-ISG-2012-02. The staff performed a review of the UFSAR and concluded the same. It is, therefore, acceptable that no indoor tanks were added to the "scope of program."

(b) Conducting a one-time ultrasonic inspection of one of the CST bottoms per station, as long as the cathodic protection provided to the tanks meets the availability and effectiveness acceptance criteria of LR-ISG-2011-03, is consistent with LR-ISG-2012-02. The cathodic protection system can ensure that further loss of material on the tank bottom will not occur. The timing of the inspection ensures that loss of material that may have occurred in earlier periods when the cathodic protection may not have been effective can be identified.

The staff's concern described in RAI B.2.1.17-2 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," and "detection of aging effects" program elements associated with an 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.2.1.17 includes an exception to the "scope of program," "preventive actions," and "detection of aging effects" program elements. The applicant stated that it will perform visual inspections at selected locations of the aluminum tank external surface and that it will remove the lagging and insulation on a sample basis to demonstrate that the lagging, roof flashing, insulation, and the sealant are effective in preventing moisture intrusion and in preventing significant loss of material to the aluminum tank external surface. The details and staff evaluation regarding the external bare metal inspections related to this exception are addressed in the response to RAI B.2.1.17-1, above.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.17-1 and B.2.1.17-2, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of LR-ISG-2012-02. The staff also reviewed the exception associated with the "scope of program," "preventive actions," and "detection of aging effects," program elements, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.17 summarizes OE related to the Aboveground Metallic Tanks Program. The applicant stated that, at Byron, in March 2011, degraded sealant, although capable of performing its intended function, was discovered at the lagging on several locations of the Unit 2 CST. In August 2012, a visual inspection of the Unit 2 CST revealed that the flashing, lagging, and insulation on the underside of the roof overhang at the top of the tank wall had dropped approximately 1-1/2 in. from the roof of the tank. This resulted in a gap at the top of the tank, which could allow rainwater to wet the insulation under the lagging. An extent of condition review revealed that similar, but less significant, degradation had occurred on the Unit 1 CST. The conditions were entered in the CAP and work order activities have been planned. The applicant also stated that at Braidwood, in July 2007, water seepage was identified on the concrete foundation of the Unit 1 CST. Investigations revealed that the lagging at the top of the CST had dropped approximately 1 in. breaking the seal between the flashing and the lagging. An extent of condition review demonstrated that the same condition subsequently occurred on the Unit 2 CST. The lagging and flashing were repaired on both tanks.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

During its review, the staff identified OE for which it determined the need for additional clarification and resulted in the issuance of an RAI, as discussed below. During the audit, the staff noticed that at Braidwood an internal indication exists in the tank wall above the water line of the Unit 2 CST. The staff lacked sufficient information to determine that the indication was not a crack. The LR-ISG-2012-02 recommends that a one-time inspection be conducted for the internal surfaces of an aluminum tank exposed to treated water. The staff believes that with a known indication as described above, periodic inspections would be appropriate if the indication was not repaired prior to the period of extended operation. By letter dated February 18, 2014, the staff issued RAI B.2.1.17-3 requesting that if the indication is not repaired prior to the period of extended operation, the applicant state either (a) the basis for why no condition monitoring activities are required to provide reasonable assurance that the indication will not affect the CST's CLB intended function(s), or (b) what condition monitoring activities will be conducted for the indication during the period of extended operation.

In its response dated March 4, 2014, the applicant stated that an internal video inspection conducted in 2008 identified an indication just below the tank roof and above the water line. The applicant performed a followup inspection in 2009 using a high resolution camera and noted no change in the length, width, or physical appearance. It initiated a recurring maintenance activity to conduct an inspection every 5 years starting in 2014. It also incorporated periodic inspections into the Aboveground Metallic Tank Program. The applicant also stated that if a physical repair is performed, it would not conduct the periodic inspections.

The staff finds the applicant's response acceptable because: (a) a followup inspection in 2009 did not reveal any changes in the indications characteristics, (b) five inspections prior to the period of extended operation (December 2027) will provide sufficient trending data related to potential growth of the indication, and (c) the indication is above the water line and therefore is unlikely to impact the required inventory capacity of the tank. The staff's concern described in RAI B.2.1.17-3 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B.2.1.17-3 the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which LR-ISG-2012-02 was evaluated.

UFSAR Supplement. LRA Section A.2.1.17, as amended by letter dated January 13, 2014, provides the UFSAR supplement for the Aboveground Metallic Tanks Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, as revised by LR-ISG-2012-02. The staff also noticed that the applicant committed to implement the new Aboveground Metallic Tanks Program prior to the period of extended operation with ultrasonic bottom inspections being conducted within the 5-year period prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Aboveground Metallic Tanks Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. The staff concludes that the applicant 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 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 enhancements, with GALL Report AMP XI.M30, "Fuel Oil Chemistry." The Fuel Oil Chemistry Program manages loss of material and reduction in heat transfer in piping, piping elements, piping components, tanks, and heat exchangers in a fuel oil environment. The program requires fuel oil parameters to be maintained at acceptable levels in accordance with TSs, Technical Requirement Manual, and ASTM Standards (ASTM D 0975-98/-06b, D 2709-96e, D 4057-95, and D 5452-98). Additionally, the LRA states that fuel oil tanks are periodically drained of accumulated water, cleaned, and internally inspected to minimize exposure to fuel oil contaminants. The LRA also states that the one-time inspection AMP will be used to verify the effectiveness of the Fuel Oil Chemistry Program. As amended by letters dated January 13, 2014, May 5, 2014, June 30, 2014, and August 29, 2014, the applicant enhanced the program to include managing loss of coating integrity for internally coated piping, piping components, tanks, and heat exchangers.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M30, "Fuel Oil Chemistry." The staff's evaluation of the changes to the Fuel Oil Chemistry program to address loss of coating integrity is documented in SER Section 3.0.3.3.1.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.18 includes an enhancement to the "preventive actions" program element. The applicant stated that the fire protection fuel oil storage tank will be periodically cleaned. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends periodic cleaning of tanks to allow removal of sediments.

Enhancement 2. LRA Section B.2.1.18 includes an enhancement to the "preventive actions" program element. The applicant stated that the AFW day tanks, diesel generator (DG) day tanks, essential service water makeup pump fuel oil storage tanks (Byron only), and fire protection fuel oil storage tanks will be periodically drained of water. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends periodic draining of water collected at the bottom of a tank to minimize the amount of water and the length of contact time. This measure is effective in mitigating corrosion on the inside of the diesel fuel oil tanks.

Enhancement 3. LRA Section B.2.1.18 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that the analysis for the levels of microbiological organisms will include the AFW day tanks and essential service water makeup pumps diesel oil storage tanks (Byron only). The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring fuel oil quality through receipt testing and periodic sampling of stored fuel oil. Parameters monitored include water and sediment content, total particulate concentration, and the levels of microbiological organisms in the fuel oil.

Enhancement 4. LRA Section B.2.1.18 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that the analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms will include the DG day tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring fuel oil quality through receipt testing and periodic sampling of stored fuel oil. "Parameters monitored or inspected" include water and sediment content, total particulate concentration, and the levels of microbiological organisms in the fuel oil.

Enhancement 5. LRA Section B.2.1.18 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that analysis for water and sediment content and the levels of microbiological organisms will include the DG fuel oil storage tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring fuel oil quality through receipt testing and periodic sampling of stored fuel oil. Parameters monitored include water and sediment content, total particulate concentration, and the levels of microbiological organisms in the fuel oil.

Enhancement 6. LRA Section B.2.1.18 includes an enhancement to the “parameters monitored or inspected” program element. The applicant stated that analysis for particulate concentration and the levels of microbiological organisms will be included for the fire protection fuel oil storage tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30, which recommends monitoring fuel oil quality through receipt testing and periodic sampling of stored fuel oil. Parameters monitored include water and sediment content, total particulate concentration, and the levels of microbiological organisms in the fuel oil.

Enhancement 7. LRA Section B.2.1.18 includes an enhancement to the “detection of aging effects” program element. The applicant stated that internal inspections of the fire protection fuel oil storage tanks are performed at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will be aligned with the recommendations of GALL Report AMP XI.M30, “Fuel Oil Chemistry.”

Enhancement 8. LRA Section B.2.1.18 includes an enhancement to the “monitoring and trending” program element. The applicant stated that the AFW day tanks and essential service water makeup pumps diesel oil storage tanks (Byron only) will include monitoring and trending for the levels of microbiological organisms. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring and trending water, biological activity, and particulate contamination concentrations in accordance with the plant’s TSs or at least quarterly.

Enhancement 9. LRA Section B.2.1.18 includes an enhancement to the “monitoring and trending” program element. The applicant stated that the DG day tanks will include monitoring and trending for water and sediment content, particulate concentration, and the levels of microbiological organisms. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring and trending water, biological activity, and particulate contamination concentrations in accordance with the plant’s TSs or at least quarterly.

Enhancement 10. LRA Section B.2.1.18 includes an enhancement to the “monitoring and trending” program element. The applicant stated that the DG fuel oil storage tanks will include monitoring and trending for water and sediment content and the levels of microbiological organisms. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring and trending water, biological activity, and particulate contamination concentrations in accordance with the plant’s TSs or at least quarterly.

Enhancement 11. LRA Section B.2.1.18 includes an enhancement to the “monitoring and trending” program element. The applicant stated that the fire protection fuel oil storage tanks will include monitoring and trending for total particulate concentration and the levels of microbiological organisms. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will ensure that the program is consistent with AMP XI.M30 which recommends monitoring and trending water, biological activity, and particulate contamination concentrations in accordance with the plant’s TSs or at least quarterly.

The staff’s evaluation of Enhancement Nos. 12 through 16 is documented in SER Section 3.0.3.3.1.

Enhancement 12. As amended by letter dated May 5, 2014, LRA Section B.2.1.18 includes an enhancement to the “detection of aging effects” program element. The applicant stated that coating inspections will be conducted by individuals certified to ANSI N45.2.6 or ASTM standards endorsed in Regulatory Guide (RG) 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Plants.”

Enhancement 13. As amended by letters dated May 5, 2014, and June 30, 2014, LRA Section B.2.1.18 includes an enhancement to the “acceptance criteria” program element. The applicant stated that indications of peeling, blistering, or delamination will be documented in the CAP.

Enhancement 14. As amended by letters dated May 5, 2014, and June 30, 2014, LRA Section B.2.1.18 includes an enhancement to the “acceptance criteria” program element. The applicant stated that when peeling, blistering, or delamination is detected and the coating is not repaired or replaced, physical testing will be conducted, where physically possible, to ensure that the coating is tightly bonded to the base metal. The applicant also stated that the testing will consist of adhesion tests endorsed in RG 1.54.

Enhancement 15. As amended by letter dated June 30, 2014, LRA Section B.2.1.18 includes an enhancement to the “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements program element. The applicant stated that an evaluation will be conducted when a coated component with indications of peeling, blistering, or delamination is returned to service without repair or replacement. The applicant also stated that the evaluation will consider the potential for degraded performance of downstream components due to flow blockage and loss of material.

Enhancement 16. As amended by letter dated June 30, 2014, LRA Section B.2.1.18 includes an enhancement to the “detection of aging effects” program element. The applicant stated that the as-left condition of a coating with indications of peeling, blistering, or delamination that is not repaired or replaced will be such that the potential for further degradation of the coating is minimized.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M30 and the staff’s recommended actions to manage loss of coating integrity as described in SER Section 3.0.3.3.1. In addition, the staff reviewed the enhancements associated with the “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.18 summarizes OE related to the Fuel Oil Chemistry Program.

Byron Station. In February 2009, Byron identified that the essential service water make-up pump fuel oil storage tank had an unsatisfactory fuel oil condition due to elevated particulate concentrations. This resulted in the flushing of the tank, instrument connections, and fuel line to the engine. The issue was entered into the CAP with an apparent cause investigation performed. Contamination of the oil by the site transport tank truck was one of the apparent causes, which led to changes in preventive maintenance program for this equipment. Periodic sampling of other fuel oil storage tanks resulted in no extent of condition concerns.

In October 2005, the 2B AFW day tank was drained, cleaned, and inspected. The inspection revealed a thin layer of dark brown material coating the interior of the tank. This finding was entered into the CAP. Planned contingency actions were implemented and the material was removed. The inspection revealed no evidence of age-related degradation. The corresponding Unit 1 tank had been inspected earlier that year with no deficiencies noted.

In November 2001, the 2B DG Fuel Oil Storage Tank was drained, cleaned, and inspected. Activities included a visual inspection of the tank interior surfaces. The coating inspection revealed a small section of coating missing on the tank wall (3 in. by 48 in. long) as well as a crack in the coating along the circumference of the floor where it joins the tank wall (approximately 3 feet long). This condition was entered into the CAP, evaluated by engineering, and found to be acceptable without repair. A volumetric inspection (UT) was performed with nominal wall thickness found. There was no pitting observed within the tank. There was no impact to the component's intended functions. Extent of condition was reviewed and found applicable to other fuel oil storage tanks, which were scheduled for tank cleanings and inspections as part of the 10-year inspection plan. Diesel fuel oil storage tank inspections took place during refuel outages through 2005, with no reported issues concerning tank coating degradation.

Braidwood. In June 2008, the 2A Diesel Fuel Oil Storage Tank was drained, cleaned, and inspected. Activities included an inspection of the tank's interior surfaces. The coating inspection revealed a small section of coating missing on the wall (2 in. by 1 in. long) as well as various areas on the floor of the tank where the coating was also missing. The coating appeared to be scraped off and the base metal left uncoated. This was attributed to activities taking place during initial construction. This condition was entered into the CAP, evaluated by engineering, and found to be acceptable without immediate repair to the coating. The visual inspection revealed no evidence of corrosion. The 2B Diesel Fuel Oil Storage Tank was inspected in August of 2008 with similar findings. Both tanks were recommended to have coatings repair during the subsequent tank cleanings. Unit 1 fuel oil storage tanks had been inspected in 2005 (1DO01TB/D) and 2007 (1DO01TA/C) with no issues identified.

In February 2007, an increasing trend in particulate concentration in the DG Fuel Oil Storage Tanks was identified and documented in the CAP. The data identified the 1B and 1D DG Fuel Oil Storage Tanks associated with the 1B DG as having the highest adverse trends. To proactively address this condition, filtering of stored oil was recommended using existing station procedural guidance. The cause was investigated and attributed to the reduction of stored inventory in the main fuel oil storage tank due to upcoming conversion to ultra-low sulfur fuel.

The smaller volume of stored fuel with the fixed level of particulate contamination caused particulate concentrations to increase as tank levels were reduced.

In June 2002, the common Fire Protection Fuel Oil Storage Tank was identified as having an unsatisfactory fuel oil condition due to elevated particulate concentrations. The issue was entered into the CAP. Immediate corrective action consisted of flushing the tank and filtering the stored oil. The cause of high particulate was the tank of the station delivery vehicle, which was found to be degraded causing contaminates to be transferred to the Fire Protection Fuel Oil Storage Tank during fueling activities. As a corrective measure, a new tank for the delivery vehicle was procured to prevent recurrence.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M30 was evaluated.

UFSAR Supplement. As amended by letters dated January 13, 2014, May 5, 2014, and June 30, 2014, LRA Section A.2.1.18 provides the UFSAR supplement for the Fuel Oil Chemistry. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the UFSAR supplement description associated with coating integrity is consistent with staff's recommended actions to manage loss of coating integrity as delineated in SER Section 3.0.3.3.1. The staff further noticed that the applicant has committed to enhance the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the Fuel Oil Chemistry Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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).

3.0.3.2.14 Reactor Vessel Surveillance

Summary of Technical Information in the Application. LRA Section B.2.1.19 describes the existing Reactor Vessel Surveillance program as consistent, with an enhancement, with GALL

Report AMP XI.M31, "Reactor Vessel Surveillance." The program provides neutron dosimetry and fracture toughness data to monitor neutron irradiation embrittlement of the ferritic RPV materials until the end of the period of extended operation in compliance with 10 CFR Part 50, Appendix H. The program also projects the extent of RPV neutron embrittlement in accordance with RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." Six specimen capsules were installed in each BBS RPV prior to plant startup, and three specimen capsules from each RPV were tested. The remaining three untested specimen capsules from each RPV are being stored in the SFP. To demonstrate compliance with the requirements of Appendix H to 10 CFR Part 50, the remaining capsules will be tested as necessary and the testing will be performed in accordance with ASTM 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M31. The staff noticed that this program provides neutron dosimetry and material data to be used in the RPV neutron embrittlement TLAAs. The staff's reviews of the applicant's TLAAs for neutron fluence projections, upper-shelf energy (USE), pressurized thermal shock (PTS), adjusted reference temperature (ART), and P-T limits are described in Sections 4.2.1, 4.2.2, 4.2.3, 4.2.4, and 4.2.5 of this SER, respectively. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as described below.

LRA Section B.2.1.19 states the applicant's withdrawal and testing of reactor vessel surveillance specimens as follows:

> There were six (6) specimen capsules installed in each Byron and Braidwood Station (BBS) RPV prior to plant startup. The capsules contain representative RPV material specimens, neutron dosimeters, and thermal monitors (eutectic alloy). All six (6) specimen capsules have been withdrawn from each of the BBS RPVs. Three (3) specimen capsules from each RPV were tested and the remaining three (3) untested specimen capsules from each RPV are currently stored in the spent fuel pool. Of the three (3) untested specimen capsules from each RPV, at least one (1) untested specimen capsule has been irradiated in excess of the projected peak neutron fluence of the associated RPV at the end of the period of extended operation. Capsules that have been withdrawn will be tested as necessary to fulfill the surveillance capsule recommendations contained in ASTM 185-82 as required by 10 CFR Part 50, Appendix H.

As referenced in the LRA, Appendix H to 10 CFR Part 50 specifies requirements for reactor vessel material surveillance programs. Appendix H to 10 CFR Part 50 states:

> Surveillance specimen capsules must be located near the inside vessel wall in the beltline region so that the specimen irradiation history duplicates, to the extent practicable within the physical constraints of the system, the neutron spectrum, temperature history, and maximum neutron fluence experienced by the reactor vessel inner surface.

Appendix H to 10 CFR Part 50 also requires that the reactor vessel material surveillance program monitor changes in the fracture toughness properties resulting from the maximum neutron fluence and the thermal environment experienced by the ferritic materials in the reactor vessel beltline. Changes to the surveillance program require NRC approval prior to implementation in compliance with Appendix H to 10 CFR Part 50.

In addition, GALL Report AMP XI.M31 states that one capsule should be withdrawn at an outage in which the capsule receives a neutron fluence of between 1 and 2 times the peak reactor vessel wall neutron fluence at the end of the period of extended operation and be tested in accordance with ASTM E185-82. The staff noticed that since no exceptions are identified in LRA Section B.2.1.19, the applicant's submittal for capsule withdrawal and testing should be consistent with GALL Report AMP XI.M31. However, the LRA does not address applicant's submittal for the surveillance specimens which have been exposed to a neutron fluence of between 1 and 2 times the peak reactor vessel wall neutron fluence at the end of the period of extended operation.

By letter dated December 12, 2013, the staff issued RAI B.2.1.19-1, Part 1, requesting that the applicant provide an updated surveillance capsule withdrawal schedule for each unit, including but not limited to: (a) identification of the capsule and associated neutron fluence value which will provide test results consistent with the GALL Report recommendation and (b) identification of a date for the submittal of each summary TR.

In its response dated January 13, 2014, the applicant provided its updated surveillance capsule withdrawal schedule for each unit as described in Table 3.0.3.2.14-1 below. The applicant stated that one surveillance capsule per reactor vessel, irradiated to a neutron fluence of 1 to 2 times the projected peak neutron fluence at the end of the period of extended operation, will be withdrawn from the SFP and tested. The applicant also stated that the summary TR for each tested capsule will be submitted to the staff prior to entering the associated period of extended operation.

Table 3.0.3.2.14-1 Updated Capsule Withdrawal Schedule in the Response to RAI B.2.1.19-1

Reactor Vessel (Station, Unit)	Capsule ID	Capsule Fluence (n/cm^2) E > 1.0 MeV
Byron, Unit 1	Y	3.97×10^{19}
Byron, Unit 2	Y	4.19×10^{19}
Braidwood, Unit 1	V	3.71×10^{19}
Braidwood, Unit 2	V	3.73×10^{19}

In addition, the applicant stated that the neutron fluence of the last-tested capsule for each unit is greater than the neutron fluence projected at the beginning of the period of extended operation. The applicant further stated that the capsule report submittal date of prior to the period of extended operation ensures a sufficient time (i.e., 0.8 to 5.4 years depending on unit) for NRC review before the actual reactor vessel neutron fluence exceeds the neutron fluence of the last-tested capsule. The applicant identified the updated withdrawal schedule for testing as a program enhancement (Enhancement 2) and revised the UFSAR supplement (LRA Section A.2.1.19) accordingly.

In its review of the applicant's response, the staff noticed that Appendix H to 10 CFR Part 50 states, "Each capsule withdrawal and the test results must be the subject of a summary technical report to be submitted…within 1 year of the date of capsule withdrawal, unless an extension is granted by the Director, Office of Nuclear Reactor Regulation." The staff also noticed that the BBS PTLRs include tables for surveillance capsule withdrawal schedules and state that "surveillance capsule testing has been completed for the original operating period. Other capsules will be removed to avoid excessive fluence accumulation should they be needed to support life extension." The staff further noticed that the surveillance capsule withdrawal schedule for the original operating license is no longer applicable upon issuance of a renewed license.

In addition, the staff determined that the applicant did not clearly address the withdrawal dates and summary TR submittal dates. The staff noticed that the surveillance capsules have already received neutron fluence exposures of between 1 and 2 times the projected neutron fluence values at the end of the period of extended operation and have been withdrawn from the reactor vessel and moved to the SFP. The current surveillance capsule withdrawal schedule is applicable and limited to the current operating period. Therefore, a surveillance capsule withdrawal schedule reflecting the period of extended operation must be proposed and the proposed schedule submitted prior to implementation. The staff further finds that upon receiving a renewed operating license, the surveillance capsules identified in Table 3.0.3.2.14-1 of the January 13, 2014, response would no longer be considered standby capsules; instead, they would be considered part of the program to meet the recommendations of the GALL Report and the requirements of 10 CFR Part 50, Appendix H. The staff finds that since the standby capsules identified in Table 1 have already been removed from the reactor vessels, they should be tested and summary reports should be submitted within 1 year of receiving the renewed license, unless the BBS submits a request for extension for approval by the Director, Office of Nuclear Reactor Regulation, within this period.

By letter dated April 24, 2014, the staff issued RAI B.2.1.19-1a requesting that, for each surveillance capsule identified in Table 3.0.3.2.14-1 of the applicant's response dated January 13, 2014, the applicant provide the withdrawal date and expected date of submittal of the summary TR. In this RAI, the staff also stated that a request for extension must be submitted for approval by the Director, Office of Nuclear Reactor Regulation, if the expected date for the submittal of the summary TR exceeds 1 year from the date of capsule withdrawal.

In its response dated May 23, 2014, the applicant stated and acknowledged that:

> Exelon understands that upon receiving a renewed operating license, the surveillance capsules, identified in Table 1 of our response dated January 13, 2014, would no longer be considered standby capsules; instead, they would be considered part of the Reactor Vessel Surveillance program to meet the NUREG-1801, Revision 2, GALL Report guidelines and the 10 CFR Part 50, Appendix H requirements. Since the capsules were previously withdrawn, the date of the issuance of the renewed license establishes the date of capsule withdrawal. Exelon also acknowledges the requirement to comply with 10 CFR 50 Appendix H, section IV.A which states: 'Each capsule withdrawal and the test results must be the subject of a summary technical report to be submitted, as specified in §50.4, within one year of the date of capsule withdrawal, unless an extension is granted by the Director, Office of Nuclear Reactor Regulation.'

However, the staff found that in its response to RAI B.2.1.19-1a, the applicant deleted information regarding the next capsule withdrawal schedule (e.g., capsules and capsule fluences) from the UFSAR supplement, program enhancement, and commitment. Therefore, the staff could not determine the adequacy of the applicant's Reactor Vessel Surveillance Program because the deleted information is necessary to confirm the program's compliance with 10 CFR Part 50, Appendix H. By letter dated July 7, 2014, the staff issued RAI B.2.1.19-1b requesting that the applicant provide a basis for the deletion of the information regarding the capsule withdrawal schedule from the UFSAR supplement, program enhancement, and commitment. The staff also requested that the applicant provide alternative information upon which the staff could assess the program's compliance with 10 CFR Part 50, Appendix H.

In its response dated July 28, 2014, the applicant revised the UFSAR supplement (LRA Section A.2.1.9), program enhancement (LRA Section B.2.1.9), and commitment (LRA Section A.5, Commitment 19) to include information regarding the next capsule withdrawal schedule, consistent with Table 3.0.3.2.14-1 above. In its revisions to the LRA, the applicant also clarified that each of the next specimen capsules will be withdrawn from the SFP to be tested and the summary TR of the capsule testing will be submitted to the staff within 1 year of receipt of the renewed license. The applicant further stated that, if a request for extension of the testing schedule is submitted in accordance with 10 CFR Part 50, Appendix H, and granted by the Director, Office of Nuclear Reactor Regulation, specimen testing will be performed in accordance with that approved extension.

The staff finds the applicant's response acceptable because the revised UFSAR supplement, program enhancement, and commitment include adequate information regarding the next capsule withdrawal schedule. The staff also finds that the applicant appropriately clarified that the summary TR of the next capsule testing will be submitted to the staff within 1 year of receipt of the renewed license unless a request for extension of the testing schedule is granted by the staff, consistent with the requirements of 10 CFR Part 50, Appendix H. The staff's concern described in RAI B.2.1.19-1, Part 1 and RAIs B.2.1.19-1a and B.2.1.19-1b was resolved.

In its review of the applicant's program, the staff also noticed that, by letter dated November 11, 2011 (ADAMS Accession No. ML113050427), the applicant provided additional information regarding its Reactor Vessel Surveillance Program to support a license amendment request dated June 23, 2011 (ADAMS Accession No. ML111790030), for a measurement uncertainty recapture (MUR) power uprate. The staff further noticed that the reactor vessel surveillance capsule withdrawal schedules for the BBS are contained in the PTLR for each unit (ADAMS Accession Nos. ML070680370, ML070240261, and ML071070447 for Braidwood Units 1 and 2, Byron Unit 1, and Byron Unit 2, respectively). In addition, the staff noticed that the neutron fluence values in the most recently submitted surveillance capsule report for each BBS unit are identical to the neutron fluence values in the PTLRs as described in Table 3.0.3.2.14-2 below.

Table 3.0.3.2.14-2 Neutron Fluence Values for Surveillance Capsule Reports/PTLRs and MUR RAI Response Submittal Dated November 1, 2011

Station, Unit	Capsule ID	Fast Neutron Fluence, E > 1.0 MeV	
		Capsule Report/PTLR (n/cm^2)	11/01/2011 Submittal (n/cm^2)
Braidwood 1	W	2.09×10^{19}	1.98×10^{19}
Braidwood 2	W	2.25×10^{19}	2.07×10^{19}
Byron 1	W	2.43×10^{19}	2.26×10^{19}
Byron 2	X	2.30×10^{19}	2.18×10^{19}

By contrast, the staff noticed that the neutron fluence values in the most recently submitted surveillance capsule report for each BBS unit differ from the values contained in the November 1, 2011, submittal. By letter dated December 12, 2013, the staff issued RAI B.2.1.19-1, Part 2, requesting that the applicant provide a basis for the change in neutron fluence values for each unit.

In its response dated January 13, 2014, the applicant stated that the neutron fluence values in the most recently submitted surveillance capsule report for each BBS unit, which are identical to the neutron fluence values in the PTLR surveillance capsule withdrawal schedules, are different from the values contained in the November 1, 2011, MUR RAI submittal due to the neutron fluence values being calculated using different NRC-approved methods.

The applicant also stated that the most recently submitted surveillance capsule report for each BBS unit documented the use of WCAP-14040-NP-A, Revision 2, for determining the surveillance capsule neutron fluence. In addition, the applicant stated that the surveillance capsule neutron fluence calculations completed for MUR were based on the NRC-approved methodologies described in WCAP-14040-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” and WCAP-16083-NP-A, Revision 0, “Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry.” The applicant further stated that these methodologies used for the previous and updated fluence calculations meet the guidance of RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

In its response, the applicant clarified that the differences in the neutron fluence values for the BBS surveillance capsules are attributed to using a methodology based on adjoint calculations in accordance with NRC-approved WCAP-14040-NP-A, Revision 2, for the capsule reports versus a methodology in accordance with NRC-approved WCAP-14040-A, Revision 4, using forward transport calculations for the MUR power uprate. As further described in Section 4.2.1 of this SER, the applicant stated that conservatisms are involved in the use of the fluence methodology in WCAP-14040-NP-A, Revision 2, because the methodology does not allow cycle-to-cycle water density variations in the peripheral fuel assemblies, bypass region, or downcomer region such that water densities were chosen in the analysis to conservatively envelope actual plant operation conditions. The applicant also stated that the use of the WCAP-14040-NP-A, Revision 2, methodology involves conservatisms in fluence calculations because it does not account for the shielding effect introduced by the former plates located at several axial elevations between the core baffle plates and the core barrel.

In its review, the staff also noticed that the license amendment request of the BBS for the MUR power uprate was approved by the staff as documented in the NRC letter dated February 7, 2014 (ADAMS Accession No. ML13281A000). The staff finds the applicant's response to RAI B.2.1.19-1, Part 2, acceptable because the applicant clarified that both the previous and updated fluence calculations for the surveillance capsules are based on NRC-approved methodologies which conform to RG 1.190 and that conservatisms are involved in the previous fluence calculations performed using the methodology in WCAP-14040-A, Revision 2.

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 enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.19, as revised by letter dated January 13, 2014, addresses an enhancement to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. This enhancement is also described in the UFSAR supplement description (LRA Section A.2.1.19) for the applicant's Reactor Vessel Surveillance Program. The applicant stated that prior to the period of extended operation, the program will establish operating restrictions to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. The applicant also stated that the operating restrictions are as follows:

- For Byron Unit 1, the cold leg operating temperature limitation is 525 °F (minimum, (274 °C)) to 590 °F (maximum, (310 °C)), and the maximum fluence for the RPV beltline materials is 3.21×10^{19} neutrons per square centimeter (n/cm^2) (E > 1.0 megaelectron volt (MeV)).
- For Byron Unit 2 and Braidwood Unit 1, the cold leg operating temperature limitation is 525 °F (minimum) to 590 °F (maximum), and the maximum fluence for the RPV beltline materials is 3.19×10^{19} n/cm^2 (E > 1.0 MeV).
- For Braidwood Unit 2, the cold leg operating temperature limitation is 525 °F (minimum) to 590 °F (maximum) and the maximum fluence for the RPV beltline materials is 3.16×10^{19} n/cm^2 (E > 1.0 MeV).

The applicant further stated that, if the RPV exposure conditions (neutron fluence and spectrum) or irradiation temperature (cold leg inlet temperature) is altered, then the basis for the projection to the end of the period of extended operation needs to be reviewed and, if deemed appropriate, updates be made to the Reactor Vessel Surveillance Program. In addition, the applicant stated that any changes to the Reactor Vessel Surveillance Program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M31 and finds it acceptable because when it is implemented it will ensure that the applicant's reactor vessels are operated under the conditions to which the surveillance capsules have been exposed and the surveillance capsule data have been evaluated, consistent with GALL Report AMP XI.M31.

Enhancement 2. As described above in this safety evaluation section, the applicant responded to RAI B.2.1.19-1 by letter dated January 13, 2014, and revised LRA Sections B.2.1.19 (program description) and A.2.1.19 (UFSAR supplement) to add an enhancement regarding the updated surveillance capsule withdrawal schedule. This enhancement is to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The applicant updated the surveillance capsule withdrawal schedule as described in Table 3.0.3.2.14-1 of this safety evaluation section and stated that the summary TR for each tested capsule will be submitted to the staff prior to entering the associated period of extended operation.

As previously discussed, the staff determined that in its enhancement, the applicant did not clearly address the withdrawal dates and summary TR submittal dates. The staff finds that capsules should be tested and summary reports should be submitted within 1 year of receiving the renewed license, unless the BBS submits a request for extension for approval by the Director, Office of Nuclear Reactor Regulation, within this period.

In the May 23, 2014, response to RAI B.2.1.19-1a, the applicant acknowledged that since the capsules were previously withdrawn, the date of the issuance of the renewed license establishes the date of capsule withdrawal. The applicant also acknowledged that, in accordance with the requirements of Appendix H to 10 CFR Part 50, each capsule withdrawal and the test results must be the subject of a summary TR to be submitted within 1 year of the date of capsule withdrawal, unless an extension is granted by the Director, Office of Nuclear Reactor Regulation. However, the staff noticed that in its response to RAI B.2.1.19-1a, the applicant deleted information regarding the next capsule withdrawal schedule (e.g., capsules and capsule fluences) from the UFSAR supplement, program enhancement, and commitment.

As previously discussed, the staff issued RAI B.2.1.19-1b to resolve this concern. In its response dated July 28, 2014, the applicant revised the UFSAR supplement, program enhancement and commitment to include adequate information regarding the next capsule withdrawal schedule. The applicant also clarified that the summary TR of the next capsule testing will be submitted to the staff within 1 year of receipt of the renewed license unless an extension of the testing schedule is granted by the staff, consistent with the requirements of 10 CFR Part 50, Appendix H. The staff's concern described in RAI B.2.1.19-1b was resolved.

Based on its audit and its review of the applicant's responses to RAIs B.2.1.19-1, B.2.1.19-1a, and B.2.1.19-1b, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M31. In addition, the staff reviewed the enhancements associated with "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The staff finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.19 summarizes OE related to the applicant's Reactor Vessel Surveillance Program. The applicant cited the analyses of excore dosimetry data which were performed to validate the applicant's fluence calculational methods and models. The applicant indicated that excore dosimetry data along with invessel dosimetry data were analyzed to demonstrate that the applicant's fluence calculations were acceptable in accordance with RG 1.190. The staff concurs that the use of the measured dosimetry data in plant-specific fluence benchmarks ensures that the program provides adequate dosimetry and material surveillance data to effectively manage loss of fracture toughness due to neutron irradiation for the reactor vessels.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant's taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.M31 was evaluated.

UFSAR Supplement. LRA Section A.2.1.19, as revised by letter dated January 13, 2014, provides the UFSAR supplement for the applicant's Reactor Vessel Surveillance Program. The UFSAR supplement also describes the program enhancements discussed above. The staff reviewed the UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1.

As described in the staff's review of Enhancement 1, the staff noticed that the UFSAR supplement describes the applicant's commitment (Commitment No. 19, item 1) that, prior to the period of extended operation, the applicant will establish operating restrictions in order to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed.

As described in the staff's review of Enhancement 2, the staff also noticed that by letter dated January 13, 2014, the applicant provided an updated capsule withdrawal schedule in response to RAI B.2.1.19-1. The applicant also committed (Commitment No. 19, item 2) to submit the summary TR for each tested capsule, which covers operations to 57 EFPY, to the staff prior to entering the associated period of extended operation. The applicant also revised the UFSAR supplement to include the updated capsule withdrawal schedule and commitment. As previously discussed, the staff noticed that in its response to RAI B.2.1.19-1a, the applicant deleted information regarding the next capsule withdrawal schedule (e.g., capsules and capsule fluences) from the UFSAR supplement, program enhancement and commitment.

As previously discussed, the staff issued RAI B.2.1.19-1b to resolve this concern. In its response dated July 28, 2014, the applicant revised the UFSAR supplement, program enhancement and commitment to include adequate information regarding the next capsule withdrawal schedule. The applicant also clarified that the summary TR of the next capsule testing will be submitted to the staff within 1 year of receipt of the renewed license unless a request for extension of the testing schedule is granted by the staff, consistent with the requirements of 10 CFR Part 50, Appendix H. The staff's concern described in RAI B.2.1.19-1b was resolved.

In its review of the applicant's UFSAR supplement against SRP-LR Table 3.0-1, the staff finds that the UFSAR supplement is an adequate summary description of the applicant's Reactor Vessel Surveillance program.

Conclusion. On the basis of its audit and its review of the applicant's Reactor Vessel Surveillance Program and responses to RAIs B.2.1.19-1, B.2.1.19-1a, and B.2.1.19-1b, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M31. In addition, the staff reviewed Enhancements 1 and 2 and confirmed that their implementation through Commitment No. 19 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff reviewed the UFSAR supplement for this AMP and finds that the information in the UFSAR supplement, as amended by letter dated July 28, 2014, is an adequate summary description of the program.

3.0.3.2.15 Buried and Underground Piping

Summary of Technical Information in the Application. LRA Section B.2.1.28 describes the existing Buried and Underground Piping Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," as modified by LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks.'" The AMP addresses the external surfaces of buried and underground piping in order to manage the effects of loss of material at BBS as well as cracking and change in material properties at Braidwood only. The AMP proposes to manage these aging effects through preventive and mitigative techniques, such as external coatings, the application of cathodic protection, and the quality of backfill utilized. The program also relies on periodic inspection activities, including visual examination, manual examination of polymeric materials, and electrochemical verification of the effectiveness of the cathodic protection system. The LRA states that there are no in-scope buried or underground tanks. The buried fire protection system piping was installed in accordance with NFPA 24, "Standard for the Installation of Private Fire Service Mains and their Appurtenances," and is annually tested for leakage, and therefore, excavated direct visual examinations of this piping is not required.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of LR-ISG-2011-03. For the "scope of program," "detection of aging effects," and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "scope of program" program element in LR-ISG-2011-03 recommends that all buried and underground piping should be in the scope of the Buried and Underground Piping program. However, during its audit, the staff found that LRA Table 3.3.2-22 states that piping and piping components exposed to concrete (external) have no AERM and no AMP is needed. Plant-specific note 4 states that the piping is embedded in the reinforced concrete foundation of the turbine building complex and this area, including any potential ground water exposure, is considered oxygen deficient and not conducive to active corrosion. The staff noticed that based on figures in the UFSAR, it appears that the ground water table is near this piping. An Illinois State Water Survey, "Dissolved Oxygen and Oxidation-Reduction Potentials in Ground Water," April 1986, not associated with the applicant's site, states that DO concentrations were near saturation 9 feet below the water table. By letter dated December 13, 2013, the staff issued RAI B.2.1.28-1 requesting that the applicant state the basis for why the area in the vicinity of the service water piping embedded in the reinforced concrete foundation of the turbine building should be considered oxygen deficient and why aging effects are not anticipated to occur or state what aging effect should be managed and which AMP is proposed.

In its response dated January 13, 2014, the applicant stated that the area regarded as oxygen deficient is that which is in direct contact with the piping embedded in the foundation of the building. In order for active corrosion to progress, a constant replenishing source of water would be required to deliver new sources of DO that could sustain an oxidizing reaction. The applicant acknowledged that permeability of the reinforced concrete could potentially allow small amounts of water to seep into the concrete foundation and contact the piping. The applicant concluded that there are no means to visually verify the assumed conditions on the underside of the turbine building foundation, and therefore revised LRA Table 3.3.2-22 to state that the Buried and Underground Piping Program will be used to manage loss of material on the external surfaces of this piping. The applicant also deleted plant-specific note 4 and revised LRA Section B.2.1.28 accordingly. As a result of an extent of condition review, the applicant revised LRA Tables 3.3.2-12 and 3.4.2-3 to include similar portions of the carbon steel piping for the fire protection and main condensate and feedwater systems within the scope of the Buried and Underground Piping Program.

The staff finds the applicant's response acceptable because the applicant appropriately included all in-scope piping embedded in the reinforced concrete foundation of the turbine building complex within the scope of the Buried and Underground Piping Program. The staff's concern described in RAI B.2.1.28-1 is resolved.

The "detection of aging effects" program element in LR-ISG-2011-03 recommends that cathodic protection and coatings be provided for buried in-scope piping, and that inspection locations be based on risk (i.e., susceptibility to degradation and consequences of failure). However, during the audit, the applicant stated that the in-scope makeup water piping from the river screen house is buried in concrete, not coated, and is provided with cathodic protection. The applicant also stated that it is not currently possible to verify the level of cathodic protection provided to this portion of the piping system. It was not clear to the staff how the risk level of this piping will be established for determining site inspection priorities given that the level of cathodic protection cannot be verified. By letter dated December 13, 2013, the staff issued RAI B.2.1.28-2 requesting that the applicant state how risk ranking factors will be determined for this piping.

In its response dated January 13, 2014, the applicant stated that cathodic protection test locations are currently being installed to evaluate the degree of cathodic protection provided to each of the two service water makeup pipes embedded in reinforced concrete. The applicant also stated that until such time that the test locations are installed and used during cathodic protection surveys, the assigned susceptibility value will assume that cathodic protection is either not present or not functional.

The staff finds the applicant's response acceptable because the applicant will not credit the cathodic protection effectiveness until it can be demonstrated by testing, and given that the Buried and Underground Piping program will be consistent with LR-ISG-2011-03, inspection locations can be appropriately determined. The staff's concern described in RAI B.2.1.28-2 is resolved.

The "acceptance criteria" program element in LR-ISG-2011-03 recommends that use of a 100 mV polarization criterion to assess the effectiveness of the cathodic protection system should only be used where the effects of mixed metal potentials are shown to be minimal. Enhancement No. 9 states that the 100 mV polarization criterion can be demonstrated effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured. Based on the information provided in the LRA, the staff lacked sufficient information related to how coupons, electric resistance probes, or reference cells will be used. By letter dated December 13, 2013, the staff issued RAI B.2.1.28-3 requesting that the applicant state which industry consensus standards will be used to install and use the corrosion rate monitoring devices, and the acceptance criteria for general and pitting corrosion rates.

In its response dated January 13, 2014, the applicant stated that:

> Soil corrosion (electrical resistance) probes will be uncoated and placed in the immediate vicinity of the buried piping it is representing. For each installation application, two probes will be installed; one connected to the cathodic protection system and one left unprotected. Information provided in National Association of Corrosion Engineers (NACE) International Publication 05107, 'Report on Corrosion Probes in Soil or Concrete,' will be considered during the application, installation, and use of soil corrosion probes. However, the specific details on installation and use of the soil corrosion probes will be in accordance with vendor, manufacturer, and NACE qualified cathodic protection expert recommendations.

The applicant also stated that:

- The observed corrosion rate will serve as a means to assess how effective the cathodic protection system is, for the given surveillance period, in mitigating corrosion at a simulated coating holiday.
- When the -850 mV instant-off criterion is not met, the following acceptance criteria may be used to assess cathodic protection effectiveness during the annual surveys:
    - A measured corrosion rate from the soil corrosion probes of 1 mil per year (mpy) or less will demonstrate that the cathodic protection system has provided effective protection for that surveillance year and no further evaluation is necessary. The loss of material rate will be established based on the past 1 year of measurements taken on a monthly frequency in conjunction with rectifier readings.
    - If the measured corrosion rate for the given surveillance year exceeds 1 mpy, the corrosion rate will be used as an input into a remaining life calculation for the component. If the measured corrosion rate indicates that the remaining life of the pipe exceeds the life of the plant, it will be concluded that the cathodic protection system has been effective in mitigating significant corrosion for that surveillance year at the location of interest. The remaining life calculation will be based on previous volumetric wall thickness measurements, annual corrosion rates, and cumulative total loss of material since the last volumetric measurements, and the current year's measured corrosion rate extrapolated through the end of the life of the plant.
    - If the observed corrosion rates from the probes, over the given surveillance year, do not support the conclusion that the intended function of the component would be maintained through the period of extended operation, it will be concluded that the cathodic protection system has not been effective over the surveillance

interval. The measurements will count against the cathodic protection effectiveness determinations performed in accordance with LR-ISG-2011-03, Table 4a, Footnote 2.c.iii.

- Buried coupons will not be used to verify the effectiveness of the cathodic protection system or support use of the -100 mV criterion.
- The applicant revised LRA Sections A.2.1.28 and B.2.1.28 (Enhancement No. 9) to state:

  In performing cathodic protection surveys, only the -850 mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness. Alternatively, soil corrosion, or electric resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys. An upper limit of −1200 mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings.

The staff finds the applicant’s response acceptable, in part, because:

- Based on a review of NACE International Publication 05107, electrical resistance soil corrosion probes are capable of measuring corrosion rates of the probe by correlating increases in electrical resistance to a loss of material of the probe. The rate of corrosion of the probe provides a direct indication of the effectiveness of the cathodic protection system in the vicinity of the probe.
- NACE International Publication 05107 provides guidance on the installation and use of electrical resistance probes including: material type, size of probe, soil contact, proximity to the piping it is representing, circuit configurations, corrosion rate calculation formulas, and acceptance criteria. Use of the guidance of this publication in conjunction with vendor, manufacturer, and NACE qualified cathodic protection expert recommendations can result in effectively determining the corrosion rate of buried components.
- The 1 mpy acceptance criterion is consistent with NACE International Publication 05107. The two-fold acceptance criterion (i.e., 1 mpy, remaining life calculation) is sufficient to provide reasonable assurance that either local cathodic protection is effective or ineffective, as the case may be; therefore in turn, providing reasonable assurance that a buried in-scope component will be capable of meeting its CLB intended function. However, the staff had a followup question related to the plant-specific application of the 1 mpy acceptance criterion as described below in RAI B.2.1.28-3a.
- When the two-fold acceptance criterion is not met, the applicant will declare that the cathodic protection at that location has not been demonstrated to be effective. This is consistent with LR-ISG-2011-03, which recommends that all cathodic protection survey points be evaluated to determine whether the cathodic protection system met an overall 80 percent effectiveness criterion for the specific interval.

The staff did not find the applicant’s response acceptable, in part, because:

- Although the 1 mpy acceptance criterion is a standard industry value used to demonstrate an effective cathodic protection system, the staff lacked sufficient information to conclude that there is reasonable assurance that all buried in-scope piping would be capable of meeting its CLB intended function with 60 mils of corrosion that could occur through the end of the period of extended operation.

- The applicant stated that, "[f]or each installation application, two (2) probes will be installed; one connected to the cathodic protection system and one left unprotected." It was not clear to the staff whether the phrase, "for each installation application," applies to each cathodic protection survey data point that did not meet the negative 850 mV polarization potential acceptance criterion during the evaluation cathodic protection survey results.
- The applicant stated that, "[t]he remaining life calculation will be based on previous volumetric wall thickness measurements, annual corrosion rates and cumulative total loss of material since the volumetric measurements, and the current years' measured corrosion rate extrapolated through the end of the life of the plant." It was not clear to the staff how the existing wall thickness will be determined when the specific location has not been volumetrically examined to determine the wall thickness. It was also not clear whether nominal wall thickness or maximum wall thickness (e.g., nominal wall thickness plus 12-1/2 percent) will be used to determine the as-found corrosion rate when volumetric examinations have been conducted to determine wall thickness.
- Neither LRA Section B.2.1.28 or Enhancement No. 9, as revised by the response to RAI B.2.1.28-3, states that NACE International Publication 05107 along with input from vendor, manufacturer, and NACE qualified cathodic protection experts will be used as input for specific details on the installation and use of the soil corrosion probes. The staff considers this input to be necessary to ensure that accurate corrosion rate data will be obtained by the soil corrosion probes.

By letter dated April 17, 2014, the staff issued RAI B.2.1.28-3a requesting that the applicant state: (1) whether all buried in-scope components will be able to perform their CLB intended function(s) if 60 mils loss of material were to occur through the end of the period of extended operation, (2) whether 2 probes will be installed (one connected to the cathodic protection system and one left unprotected) at each cathodic protection survey data point that did not meet the negative 850 mV polarization potential acceptance criterion during cathodic protection surveys, (3) how the existing wall thickness of buried in-scope components will be determined when the component has not been volumetrically examined to determine the wall thickness, and (4) the basis for how as-found corrosion rates will be determined for buried in-scope piping components. In addition, the staff requested that the applicant revise LRA Section B.2.1.28 or Enhancement No. 9 to state the sources of guidance that will be used to develop specific details on installation and use of the soil corrosion probes.

In its response dated May 15, 2014, the applicant stated that:

(1) A review of minimum wall calculations previously prepared for in-scope piping was performed, and for piping segments without pre-existing minimum wall calculations, a comparison of critical piping characteristics (e.g., piping specifications, system design information, pipe diameter) was performed. These calculations and comparisons demonstrated that considering all design loads (i.e., hoop stress, axial stress, soil overburden) all buried in-scope piping is capable of withstanding at least 60 mils of material loss from 87.5 percent of the nominal thickness.

(2) Soil corrosion probes will not necessarily be installed at each cathodic protection survey test point. Most often, the soil corrosion probe assemblies will be installed away from existing cathodic protection test points. With regard to the selection of soil corrosion probe locations and utilization of the data: (a) NACE qualified cathodic protection experts will assist In selecting the location(s); (b) "[g]enerally, both the soil corrosion probes and the permanent reference electrode are installed below-grade and in close proximity to the buried piping of interest"; (c) a NACE qualified cathodic protection expert will evaluate the difference in the respective locations between the soil corrosion probes and the existing test point to determine whether the difference in the relative data could be reasonably attributed to other significant site features (e.g., exposed large surface area tank bottoms, heavily congested areas of other buried piping, very large diameter pipes); and (d) if the difference in the observed data could be attributed to adjacent site features, cathodic protection effectiveness at the existing test point will not be evaluated by use of data from the soil corrosion probes. The applicant revised the program to cite NACE International Publication 05107, "Report on Corrosion Probes in Soil or Concrete," as a reference to be considered during the application, installation and use of the soil corrosion probes.

(3) Soil corrosion probe data will only be used in locations where in-scope buried piping has been volumetrically examined.

(4) As-found corrosion rates (i.e., corrosion rate since initial construction) will not need to be determined based on the following. As-found pipe wall thickness values will be obtained from volumetric examinations conducted during previous excavations and inspections (i.e., during installation of the probes). Subsequent corrosion rate data will be obtained from the soil corrosion probe results. The observed corrosion rate obtained from the last annual survey year will be assumed to be constant and projected through the end of the period of extended operation. The effectiveness of the cathodic protection system using the soil corrosion probe results is determined on an annual basis.

The staff finds the applicant's response to RAI B.2.1.28-3a acceptable, in part, because the applicant's review of available margin in buried in-scope piping systems confirmed that all design loads can be satisfied with 60 mils of material loss from the minimum supplied pipe wall thickness. In addition, as described in the response to part (d) of this RAI, herein, when the applicant uses the soil corrosion probe data as-found corrosion to date will be available because the soil corrosion probe data will only be used when volumetric wall thickness measurements of the piping of interest has been obtained coincident with installation of the probes.

However, the staff found that:

- NACE offers four levels of qualification consisting of cathodic protection tester, cathodic protection technician, cathodic protection technologist, and cathodic protection specialist (NACE Courses CP 1 through CP 4). It was not clear to the staff what level of qualification the applicant will use to determine locations of soil corrosion probes and for determining the impact of localized site features.

- Local soil conditions (e.g., moisture content, pH, resistivity) could be impactful. For example, if the soil in the vicinity of the soil corrosion probe were less corrosive than at other pipe segment locations, the soil corrosion probe could under-predict the corrosion rate at other points of interest along the pipe length.
- NACE International Publication 05107 Section 3 recommends that the probe should be installed close to the pipe or structure. Appendix B recommends that the probe be installed 10 in. from the pipe. Based on the use of the term "generally," it was not clear to the staff whether soil corrosion probes will be located in close proximity to the pipe locations of interest.
- The applicant did not state the factors it will consider when evaluating the impact of local site features. NACE International Publication 05107 does not contain recommendations associated with the impact of local site features.

By letter dated June 23, 2014, the staff issued RAI B.2.1.28-3b Request (1) requesting that the applicant state: the level of NACE cathodic protection qualification of the individuals involved in selecting soil corrosion probes and for determining the impact of localized site features; how local soil conditions will be factored into use of the soil corrosion probe data; whether soil corrosion probes will be installed in close proximity to the buried piping of interest; and what factors will be considered when evaluating local site features including examples of how the factors would be applied. In addition the staff requested that the applicant make appropriate changes to LRA Section B.2.1.28.

In its response dated July 18, 2014, the applicant stated that:

- Individuals that determine the location of future soil corrosion probes will be qualified to NACE CP4, Cathodic Protection Specialist. LRA Section B.2.1.28 was revised to include this qualification level.
- LRA Section B.2.1.28 was revised to state that the placement of soil corrosion probes will consider existing soil data, "(e.g., moisture content, pH, and resistivity measurements)." The applicant stated that soil sampling is conducted as a best practice when excavating buried pipe.
- The term "generally" was deleted in reference to the location of soil corrosion probes. LRA Section B.2.1.28 was revised to state, "[placement of soil corrosion probe assemblies will] be in close proximity to the buried pipe of interest."
- The factors that will be considered when evaluating the impact of adjacent site features include the presence of "large cathodic protection current collectors," and shielding caused by large diameter components located in the vicinity of cathodically protected components. Both of these features could result in less protection provided to cathodically protected components. The applicant provided two example scenarios, which represented a condition where the soil corrosion would provide effective input related to the protection provided to buried components and one where the soil corrosion probe would not provide effective input related to the protection provided to buried components. LRA Section B.2.1.28 was revised to address these factors.

The staff noticed that the NACE website, http://www.naceinstitute.org/Certification/, states that the NACE CP4 Cathodic Protection Specialist is, "geared toward those persons involved in the design, installation, and maintenance of cathodic protection systems. The staff noticed that CP4 is the highest level of certification. The staff finds the applicant's response to RAI B.2.1.28-3b Request (1) acceptable because:

(a) personnel that provide input for the location of soil corrosion probes and use of soil corrosion probe data will be appropriately qualified; (b) soil corrosion data will be factored into the placement of soil corrosion probes, which will result in the probe data not being misleading due to potential soil impacts on corrosion rates; (c) soil corrosion probes will be installed in close proximity to the buried pipe of interest; which will result in more accurate corrosion rate data; and (d) the applicant identified appropriate factors to consider for site structure impacts and demonstrated through its example scenarios where soil corrosion probes data could be used and should not be used.

The staff also noticed that the applicant had not revised its program to state that soil corrosion probe data will only be used in locations where in-scope buried piping has been volumetrically examined in conjunction with installation of the probes. By letter dated June 23, 2014, the staff issued RAI B.2.1.28-3b Request (2) requesting that the applicant revise the Buried and Underground Piping Program to state that soil corrosion probe data will only be used in locations where in-scope buried piping has been volumetrically examined in conjunction with installation of the probes.

In its response dated July 18, 2014, the applicant revised the Buried and Underground Piping program to state that, "[t]he remaining life calculation methodology may only be used when the pipe being assessed was volumetrically examined at the time the soil corrosion probe assembly was installed." The staff finds the applicant's response acceptable because as-found wall thickness measurements will be obtained when soil corrosion probes are installed and used to determine a remaining life, thus eliminating the need to project corrosion rates that have occurred since installation.

The staff's concerns described in RAIs B.2.1.28-3, B.2.1.28-3a, and B.2.1.28-3b are resolved. The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B.2.1.28, as amended by letter dated January 13, 2014, includes an exception to the "preventive actions" program element. The applicant stated that original plant specifications did not require coatings to be installed for carbon steel piping embedded in reinforced concrete. The applicant also stated that recent inspections of below grade reinforced concrete surfaces and controlled low strength material (CLSM) has shown that the cementitious material is in good condition.

The staff reviewed this exception against the corresponding program element in LR-ISG-2011-03 and finds it acceptable because the alkaline environment of concrete provides steel with corrosion protection; plant-specific inspections have demonstrated that the concrete is in good condition. Therefore, there is a low likelihood that water and contaminants are being admitted to the bare steel surfaces of the piping; and the piping is cathodically protected, which minimizes the potential for loss of material.

Exception 2. LRA Section B.2.1.28 includes an exception to the "preventive actions" program element. The applicant stated that underground carbon steel service water system piping at Braidwood is coated with BIO-GARD™ 258, manufactured by Thin Film Technology, Inc. BIO-GARD™ 258 is a liquid epoxy polymer based coating that is reinforced with Kevlar™ fibers. The applicant also stated that the program has been enhanced to inspect each underground segment at least once every 10 years beginning 10 years prior to the period of extended operation.

The staff noticed that the product data sheet for BIO-GARD™ 258 states that it is recommended for use in marine and industrial heavy duty applications. The staff also noticed that NACE Standard RP0285-2002, "Standard Recommended Practice, Corrosion Control of Underground [Buried] Storage Tank Systems by Cathodic Protection," Section 3.4, "Coatings," states that epoxy based coatings are one of three types commonly used on steel tanks.

The staff reviewed this exception against the corresponding program element in LR-ISG-2011-03 and finds it acceptable because the coating is intended for use in environments that are more adverse than the underground environment to which it will be exposed. NACE Standard RP0285-2002 recognizes that this type of coating is commonly used on buried tanks; and periodic visual inspections will be conducted, which are capable of detecting degradation of the coatings and loss of material.

Exception 3. LRA Section B.2.1.28 includes an exception to the "detection of aging effects" program element. The applicant stated that it will perform one direct inspection within the first 10 years during the period of extended operation on high-density polyethylene (HDPE) polymeric piping, with SS piping elements, which are within the scope of license renewal (Braidwood only). The applicant stated that in 2008, a buried carbon steel main condensate and feedwater system pipe was cut at both ends of a building under which it ran. An HDPE polymeric pipe sleeve was inserted through the portion of the carbon steel pipe that is under the building and on each side of the building. the HDPE pipe was connected to an SS piping reducer and welded to the remaining upstream and downstream portions of the original carbon steel pressure boundary portion of piping. The SS piping reducers were coated with a silicon-ceramic coating and polymeric tape wrap. The HDPE polymeric and SS piping and components were backfilled using compacted sand placed within 6 in. of the pipe.

The staff noticed that LR-ISG-2011-03 Table 4a recommends that one inspection be conducted on buried polymeric and SS piping in the 30 to 40 year period of operation. Subsequent to this inspection, one inspection is conducted in each of the next 10-year periods. The staff also noticed that the renewed licenses for the Braidwood units will expire in 2046 and 2047. Given that the components were installed in 2008, the staff's expectation would be that one inspection would be conducted in the 2038 to 2048 time frame. As stated by the applicant, the inspection could occur as early as 2026.

The staff reviewed this exception against the corresponding program element in LR-ISG-2011-03 and finds it acceptable because (a) the components would have been buried for 18 years at the earliest date of an inspection, which would provide sufficient time for degradation of the coatings to be noted; (b) backfilling using compacted sand placed within 6 in. of the pipe results in a very low likelihood that any damage will occur to the coatings on the SS pipe and outside surfaces of the HDPE piping; and (c) coated SS piping and HDPE piping are highly resistant to loss of material in a buried environment with appropriate backfill.

Exception 4. LRA Section B.2.1.28 includes an exception to the "preventive actions" and "detection of aging effects" program elements. The applicant stated that managing aging effects of the buried fire protection system piping will be accomplished through annual fire protection system leakage testing. The applicant stated that testing is accomplished by initially running the jockey pump to achieve an elevated and constant system pressure, shutting down the jockey pump, monitoring of the pressure decrease over the duration of the test (typically 1 hour), recording the final pressure and surveillance time, determining a decay rate, and then comparing this to a baseline decay rate acceptance criteria.

The staff noticed that LR-ISG-2011-03, Section 2.a.ii., allows a periodic flow test in accordance with NFPA 25, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems” to be used in lieu of the preventive measures recommended in Table 2a, “Preventive Actions for Buried Piping and Tanks,” for fire protection systems installed to the requirements of NFPA 24.

The staff reviewed this exception against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because the annual fire protection system leakage test is at least as effective as a flow test to detect component degradation.

Enhancement 1. LRA Section B.2.1.28 includes an enhancement to the “parameters monitored or inspected” and “detection of aging effects” program elements. The applicant stated that it will perform manual examinations, in addition to visual inspections, to detect hardening, softening, or other changes in material properties for buried polymeric piping (Braidwood only).

The staff noticed that the “detection of aging effects” program element of GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” recommends that physical manipulation of flexible polymeric components accompany visual inspections. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will ensure that both visual inspection and physical manipulation will be conducted during inspections of buried polymeric components.

Enhancement 2. LRA Section B.2.1.28 includes an enhancement to the “parameters monitored or inspected” program element. The applicant stated that cracking will be managed for SS components, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed and expose the base material (Braidwood only). The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will be consistent with the guidance in the GALL Report.

Enhancement 3. LRA Section B.2.1.28 includes an enhancement to the “preventive actions” program element (Byron only). The applicant stated that it will ensure that all underground carbon steel essential service water system piping within the scope of license renewal is coated in accordance with NACE SP0169-2007, “Standard Practice, Control of External Corrosion on Underground or Submerged Metallic Piping Systems,” prior to the period of extended operation. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented (Byron only), it will ensure that appropriate coatings are applied to the external surfaces of underground service water system piping.

Enhancement 4. LRA Section B.2.1.28 includes an enhancement to the “parameters monitored or inspected” and “acceptance criteria” program elements. The applicant stated that direct visual inspections of coated piping and components will be performed by an individual possessing a NACE Coating Inspector Program Level 2 or 3 operator qualification or by an individual who has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course. The staff reviewed this enhancement against the corresponding program elements in

LR-ISG-2011-03 and finds it acceptable because when it is implemented it will ensure that an individual with the appropriate knowledge, skills and abilities will perform coatings inspections.

Enhancement 5. LRA Section B.2.1.28 includes an enhancement to the “detection of aging effects” program element. The applicant stated that the number of inspections of buried piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a and based upon the as-found results of cathodic protection system availability and effectiveness during each 10-year period, beginning 10 years prior to the period of extended operation. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable when it is implemented it will be consistent with the guidance in the GALL Report.

Enhancement 6. LRA Section B.2.1.28 includes an enhancement to the “preventive actions” and “detection of aging effects” program elements. The applicant stated that a long term mitigation strategy will be applied to the buried carbon steel condensate system piping within the scope of license renewal prior to entering the period of extended operation. The mitigation may include activities such as fully recoating, complete replacement with like or upgraded material, installation of internal polymeric sleeves, and routing of pipe above ground or in an engineered trench for leak detection. The applicant also stated that inspections of the condensate system piping will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based on the mitigation strategy implemented (Braidwood only).

The staff noticed that this enhancement is based on plant-specific OE related to degradation of buried in-scope condensate system piping. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will reduce the potential for loss of material (e.g., recoating, upgraded material), extend the life of the system (if a like-for-like replacement is implemented), or provide for on-line leak detection, all of which provide reasonable assurance that the condensate system piping will be able to perform its CLB intended function.

Enhancement 7. LRA Section B.2.1.28, as amended by letter dated January 13, 2014, includes an enhancement to the “detection of aging effects” program element. The applicant stated that inspections of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10-year period, beginning 10 years prior to the period of extended operation. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will ensure that periodic inspections are conducted that are capable of detecting coating degradation or loss of material for the in-scope underground components.

In addition, this enhancement states that the piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications. The staff’s evaluation of this portion of the enhancement is documented in the response to RAI B.2.1.28-4.

Enhancement 8. LRA Section B.2.1.28 includes an enhancement to the “detection of aging effects” program element. The applicant stated that if adverse indications are detected during inspection, inspection sample sizes within the affected piping categories will be doubled; and if adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause with the size of the follow-on inspections determined based on the analysis. The applicant also stated that timing of the additional inspections will be based on the severity of the identified degradation and the consequences of leakage; however, the additional inspections will be performed within the same 10-year inspection interval in which the original adverse indication was identified. The applicant further stated that expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented, it will be consistent with the recommendations in the "detection of aging effects" program element associated with adverse conditions. These program activities can ensure that the quantity and timing of extent of condition inspections are sufficient to detect whether degradation of coatings or base material is pervasive or limited to that which has already been detected.

Enhancement 9. LRA Section B.2.1.28, as amended by letter dated January 13, 2014, includes an enhancement to the "acceptance criteria" program element. The applicant stated that the acceptance criteria for determining the effectiveness of the cathodic protection system will be based on either the −850 mV polarized potential criterion specified in NACE SP0169-2007, or soil corrosion, or electric resistance, probes. The applicant also stated that an upper limit of −1200 mV pipe-to-soil potential will be established. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because the −850 mV and −1200 mV values are consistent with the recommendations in LR-ISG-2011-03. The staff's evaluation of the use of soil corrosion probes is documented in the response to RAI B.2.1.28-3, B.2.1.28-3a, and B.2.1.28-3b.

Enhancement 10. LRA Section B.2.1.28 includes an enhancement to the "acceptance criteria" program element. The applicant stated that an extent of condition evaluation will be conducted if observed coating damage caused by nonconforming backfill has been evaluated as significant. The extent of condition evaluation will be conducted to ensure that the as-left condition of backfill in the vicinity of the observed damage will not lead to further degradation. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will be consistent with the "acceptance criteria" program element of LR-ISG-2011-03 and can ensure that an adequate extent of condition review is conducted with the intent that the extent of nonconforming backfill in the vicinity of observed damage would be understood and corrected.

Operating Experience. LRA Section B.2.1.28 summarizes OE related to the Buried and Underground Piping Program. The applicant stated that, at Byron in May 2011, it excavated and inspected nine high-risk service water system pipe segments. The pipes were found either completely backfilled in a controlled compacted fill, or, for larger diameter pipes, partially encased in a cementitious material with compacted fill around the remaining pipe surface. Coatings were generally found in good condition and well adhered. Where coating damage was observed and the pipe surface was exposed, coating damage was generally attributed to the excavation process due to the light surface corrosion and lack of pitting observed. However, in one instance, the coatings damage was likely from inadequate initial application during installation. This condition was entered into the CAP, and UT was performed with satisfactory results. A cathodic protection test point was installed for future monitoring of pipe-to-soil potentials during the annual cathodic protection survey. The applicant also stated that, at Byron in January 2009, a review of cathodic protection system trends and vendor recommendations from recent annual surveys identified a downward trend in system performance. As a result, between the fall of 2009 and spring of 2010, three of the four original deep anode beds were replaced with new anode beds. In 2010 and 2012, two of the four original rectifiers were also replaced with new rectifiers to improve performance of the system.

The applicant stated that at Braidwood, in spring and fall of 2010, it excavated and inspected three carbon steel main condensate and feedwater system pipe segments. Instances of coating damage were identified, primarily at locations of field applied tape coatings. Shop applied coatings, consistent with design specifications, were generally found in good condition and providing adequate protection to the piping. Upon removal of the coatings at the locations of isolated damage, the exposed steel pipe surface exhibited minimal surface corrosion and several small areas of localized corrosion. Ultrasonic thickness measurements were taken to confirm pipe wall thickness. Although some locations were found less than the 87.5 percent nominal wall thickness acceptance criteria, all locations exceeded minimum wall thickness requirements. Based on the maximum depths of the localized corrosion areas, conservatively estimated remaining lives were calculated for each pipe. Permanent guided wave collars were installed to allow for periodic monitoring and detection of potential changes in corrosion rates in order to better inform direct inspection schedules. Cathodic protection test points were also installed on every excavated segment to allow for more direct monitoring of cathodic protection levels. Sacrificial anodes were also added to seven segments in the third excavation to supplement the existing impressed current cathodic protection system. The applicant also stated that in 1999, an observation was made on the adverse trend in the number of corrective maintenance issues related to the cathodic protection system and as a result, corrective actions were taken in 2000 to replace the deep anode beds and rectifiers.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of RAIs as discussed below.

In the “operating experience” program element in the LRA, the applicant cited an example where at Byron, inspection personnel discovered 8-10 feet of water in an essential service water valve pit. The in-scope piping was immersed in water. The water was removed, ultrasonic thickness measurements of the piping were performed, and the piping was recoated with a protective coal tar coating and polymeric tape wrap. The inspection frequency for both essential service water valve pits at Byron was changed from every 2 years to every 3 months. During the audit, the staff reviewed the results of the preventive maintenance activities associated with the essential service water valve pits which experienced water intrusion. Of 21 inspections, 7 inspections observed 10 in. or less of water, 7 inspections provided no water quantity or level data, and 7 inspections observed 14 in. or more in the pit. The bottom of the essential service water pipe is at 18 in. Based on a review of the inspection results, it was not clear that the inspection interval at Byron was sufficient to prevent the in-scope piping from being periodically rewetted. It was also not clear to the staff that the coating system was adequate for immersion, drying, and rewetting. By letter dated December 13, 2013, the staff issued RAI B.2.1.28-4, requesting that the applicant state the basis for why the inspection interval at Byron provides reasonable assurance that the CLB intended function of in-scope piping in the pits will be met during the period of extended operation.

In its response dated January 13, 2014, the applicant stated that although water levels have, on a few occasions, resulted in exposure of the piping to standing water, the components have not been subjected to extended periods of contact with accumulated and standing water inside the vaults, and the components contained within these valve pits were recoated in 2012. The applicant also stated that in order to ensure that the intended function of the service water piping and components inside the essential service water valve pits are maintained during the period of extended operation, the maintenance activity will be enhanced to ensure direct visual inspections of the piping and components are performed by engineering. These inspections will verify the absence of any degradation to the protective coating and underlying metal. If evidence of degradation is identified, the condition will be entered into the CAP and corrective actions initiated to repair the piping, components, or protective coatings as appropriate. The applicant further stated that the quarterly surveillance may be eliminated if either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications. The applicant revised LRA Section B.2.1.28, Enhancement No. 7, and Commitment No. 28 to reflect the above response.

The staff finds the applicant's response acceptable because Enhancement No. 7 and Commitment No. 28 were revised to state that engineering will conduct the quarterly visual inspection of the piping and valves in the service water valve vaults. This enhancement converts the inspection from checking for and removing water to an evaluation that can detect coating degradation and loss of material from the components. In addition, inspections will continue until the condition is corrected by "preventive actions." Eliminating the source of the water or using a coating that is designed for periodic immersion are effective "preventive actions" that will prevent further loss of material from the in-scope components in the vault. The staff's concern described in RAI B.2.1.28-4 is resolved.

Based on a review of station inspection reports and plant-specific OE during the audit, it appears that there have been several instances of inadequate initial preparation of coatings resulting in disbondment and minor corrosion. Based on this plant-specific OE, the staff lacked sufficient information to understand the extent of condition of coating degradation and quality of the original coating installation. In conjunction with this, the staff's review of cathodic protection survey reports for both Byron and Braidwood indicate that cathodic protection coverage has been improving, but the protection level is not consistently meeting the recommendations in LR-ISG-2011-03. As a result of these observations, the staff could not conclude that the "preventive actions" and plant-specific conditions for buried piping are bounded by the conditions for which the GALL Report AMP was evaluated (e.g., quantity of inspections, frequency of inspections). By letter dated December 13, 2013, the staff issued RAI B.2.1.28-5; requesting that the applicant state the overall condition of coatings as a preventive action in relation to crediting them for the preventive action categories of LR-ISG-2011-03, Table 4a.

In its response dated January 13, 2014, the applicant provided a detailed explanation for each system. A summary of the applicant's response and staff evaluation for each system follows.

<u>*Braidwood Station In-Scope Buried Pipe Systems*</u>. Braidwood has three in-scope systems with buried components.

- Condensate system: the applicant stated that coating deficiencies for in-scope condensate system piping have been documented. Enhancement No. 6 was developed to address the deficiencies in the preventive measures associated with the buried condensate system piping. Upon implementation of Enhancement No. 6, the preventive measures in place for the buried condensate system will provide adequate protection of the in-scope piping. As a result, inspection quantities performed in accordance with LR-ISG-2011-03 Table 4a will provide reasonable assurance of the condition of buried in-scope condensate system piping, and ensure that it will continue to perform its intended function through the period of extended operation.

The staff finds the applicant's response acceptable because Enhancement No. 6, as discussed previously, will result in a mitigation strategy for the condensate system (e.g., recoating, routing pipe above ground or engineered trench to provide leak detection) prior to the period of extended operation.

- Fire protection system: the applicant stated that a number of coating flaws and highly localized corrosion had been observed during excavated fire protection system piping inspections. In some cases, the localized corrosion resulted in through-wall leakage. However, the areas surrounding the localized coating failures have been well protected and appeared in excellent condition with little to no surface corrosion. Multiple measures are in place to detect and manage system leakage including 2 jockey pumps capable of providing a total of 200 gpm makeup to the system, the configuration of the system allows for isolation of leaks in order to accomplish repairs, and multiple connections between the buried fire water ring header and safety-related structures. Control room indication of jockey pump operation is provided and continuous or excessive jockey pump operation has been previously identified, entered in the CAP, and the cause investigated and corrected. The buried portions of the fire protection system will be managed through annual system leakage testing in lieu of excavated direct visual inspections. The buried piping is relatively shallow and as a result, previous system leaks have manifested at the surface and have been easily identified by station personnel during walkdowns.

  The staff finds the applicant's response acceptable because in lieu of excavated direct visual examinations of buried fire protection system piping, the applicant will monitor jockey pump operation. Monitoring jockey pump operation is consistent with LR-ISG-2011-03.

- Service water system: the applicant stated that buried pipe coating deficiencies identified in other systems have all occurred at locations of compacted backfill. The entire length of the in-scope carbon steel service water system is backfilled in a CLSM. Backfilling of the service water pipes in CLSM limits the possibility of coating damage during the backfill process, as well as provides an additional barrier of protection to potentially damaged areas and protection against age-related degradation of the intact coating itself.

  The staff noticed that in regard to CLSM, NUREG–1950, "Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG-1801 and NUREG-1800," the response to Comment No. 1087 states, "[t]he staff concurs with the commenter that the corrosion rate of steel piping encased in controlled low strength material is substantially less than that expected for direct buried piping. As a result, the staff has reduced the priority of this type of piping in determining which pipe should be selected for inspection and has reduced the number of inspections recommended for this type of pipe." The staff finds the applicant's response acceptable because the likelihood of coating damage is lower and because the environment surrounding the buried piping is less conducive to loss of material.

Byron Station In-Scope Buried Pipe Systems. Byron has four in-scope systems with buried components.

- Condensate system: The applicant stated that the buried in-scope condensate system piping is nonsafety-related, does not contain hazardous material such as tritium and oil, and is therefore, risk-ranked low within the existing buried pipe program. As a result, no direct visual inspections of buried condensate system piping have occurred. There have been no externally initiated leaks on the buried portions of the condensate system, indicating that the undisturbed coating is providing adequate protection and/or the cathodic protection system has been effective in mitigating any significant corrosion.

  The staff finds the applicant's response acceptable because based on the function and content of the condensate system, it would not be expected that direct visual inspections would have been conducted, and because the absence of leaks provides assurance that to date, potential coating defects are not substantial.

- Fire protection system: The applicant stated that although no leaks have occurred on buried portions of the fire protection system ring header at Byron Station, the measures that are in place to detect and manage system leakage are the same as those in place at Braidwood Station, described previously.

  As discussed for Braidwood fire protection system, the staff finds the applicant's response acceptable because in lieu of excavated direct visual examinations of buried fire protection system piping, the applicant will monitor jockey pump operation. Monitoring jockey pump operation is consistent with LR-ISG-2011-03.

- Service water system: The applicant stated that approximately 95 percent of the buried carbon steel service water system piping within the scope of license renewal is backfilled in either CLSM, or encased in reinforced concrete. The remaining 5 percent is backfilled in controlled compacted fill. Of the 13 buried service water pipe inspections conducted since 2009, only one revealed degraded coatings considered to have been associated with aging (the others being associated with either damage during the excavation process or areas of previous excavations and coating repair). Ultrasonic thickness readings were taken, with the lowest area having a wall thickness greater than 64 percent of the nominal thickness. Although cathodic protection had been effective in mitigating significant corrosion, based on the general wall thickness readings taken along the entire excavated region, an additional cathodic protection test point was added to allow for more accurate trending in future surveys. In addition, at least 10 new cathodic protection test points with new reference cells immediately adjacent to the service water piping have been installed in order to provide additional information on the degree of cathodic protection.

  The applicant also stated that, based upon the approximately 300 feet of piping that has been inspected since 2009, this one identified area exhibiting age-related degradation is not considered representative and indicative of the condition of the entire 2000 foot population under consideration. However, as a result of this finding, as well as the areas of improper coating repair, implementation of an aggressive extent of condition investigation and long-term asset management strategy has begun on similar areas of interest. The applicant described placement of additional cathodic protection survey points and installation of guide wave collars and plans to recoat portions of the buried service water piping system.

  The applicant further stated that Enhancement No. 8 sufficiently addresses the potential issue of further unanticipated coating deficiencies found during inspections performed during each of the three 10-year periods, beginning 10 years prior to the period of extended operation. This expansion of scope criteria will ensure that any conditions identified, including other in-scope systems of similar materials and backfill environments, will result in evaluation and scheduling of additional inspections consistent with Element 4.f.iii of LR-ISG-2011-03.

The staff noticed that some of actions stated in this response have not been completed nor do they have corresponding enhancements and commitments (e.g., recoating of portions of the service water system, periodic monitoring and trending for potential loss of material and indications of coating holidays using permanently installed guided wave collars).

The staff also noticed that LR-ISG-2011-03 Table 4a recommends that if a cathodic protection system has been installed, but all or portions of the piping covered by that system fail to meet any of the availability or effectiveness criteria, inspection quantities of Category E in lieu of Category F can be conducted provided, in part, if no significant coating degradation or metal loss in detected in more than 10 percent of inspections conducted. Category F results in significantly more inspections than Category E (e.g., in the 30 to 40-year time period 5 percent of the piping is inspected versus 1 percent).

The staff further noticed that Enhancement No. 8 requires that the inspection sample size within an affected piping category be doubled if adverse indications are detected. However, the applicant did not address the baseline number of inspections that would be conducted in relation to the quality of its coatings.

The staff finds the applicant's response acceptable for the portions of the service water system buried in CLSM or encased in reinforced concrete because the likelihood of coating damage is lower and because the environment surrounding the buried piping is less conducive to loss of material. However, the staff lacks sufficient information to understand how the applicant will determine the number of inspections to be conducted commencing 10 years prior to the period of extended operation for the 5 percent of the service water buried piping that is backfilled in controlled compacted fill. See the staff's evaluation of RAI B.2.1.28-5a, below, for the resolution of this issue.

- Demineralized water system: The applicant stated that the buried in-scope demineralized water system includes portions of the plant's nonsafety-related well water system which provides makeup water to the essential service water cooling towers. Only one direct visual inspection of buried well water system piping has been performed. This inspection revealed a minor coating anomaly based on the observation of five small localized corrosion areas on the underlying metal which had formed on a 90° elbow. Ultrasonic measurements were taken showing all readings, except in the areas of the localized corrosion spots, to be above 89 percent nominal wall thickness. The wall thickness of the five areas of interest found on the piping elbow ranged from 60 to 85 percent nominal wall thickness. Prior to recoating and burial, a cathodic protection test point was installed to allow for more accurate cathodic protection readings and supplementary coverage. Additionally, a permanent guided wave collar was installed to allow for periodic future monitoring of pipe wall thicknesses.

  The applicant also stated that this identified coating deficiency is not considered representative of the overall buried in-scope portions of the demineralized water system because (a) coating degradation occurred at a 90° elbow which is considered to have greater susceptibility to coating damage, (b) in the approximately 2,600 feet of in-scope buried carbon steel demineralized water system piping backfilled in compacted fill, there are only approximately 20 piping elbows or tees, and (c) straight portions of the excavated piping exhibited adequate corrosion protection and lack of overall general corrosion of the underlying material, representative of the vast majority of the remainder of the in-scope system. Piping elbows receive a higher susceptibility and overall risk ranking within the buried piping program database as well, and are prioritized for inspection accordingly.

The applicant further stated that Enhancement No. 8 sufficiently addresses the potential issue of further unanticipated coating deficiencies found during inspections performed during each of the three 10-year periods, beginning 10 years prior to the period of extended operation. This expansion of scope criteria will ensure that any conditions identified, including other in-scope systems of similar materials and backfill environments, will result in evaluation and scheduling of additional inspections consistent with Element 4.f.iii of LR-ISG-2011-03.

The staff determined that Enhancement No. 8 requires that the inspection sample size within an affected piping category be doubled if adverse indications are detected. However, the applicant did not address the baseline number of inspections that would be conducted in relation to the quality of its coatings.

Although the applicant stated that the identified coating deficiency is not considered representative of the overall buried in-scope portions of the demineralized water system, the staff cannot come to the same conclusion because there has only been one inspection of this system. The staff does not find the applicant's response acceptable because the one inspection of this system revealed metal loss associated with degraded coatings. See the staff's evaluation of RAI B.2.1.28-5a, below, for the resolution of this issue.

By letter dated April 17, 2014, the staff issued RAI B.2.1.28-5a requesting that the applicant state whether more than 10 percent of the in-scope buried pipe excavated direct visual inspections at Byron have revealed metal loss or significant coating damage regardless of whether the coating degradation is age-related (except for coating damage occurring during a current excavation).

In its response dated May 15, 2014, the applicant stated that greater than 10 percent of the number of inspections have exhibited evidence of coating damage. Consistent with Enhancement No. 5, the number of inspections performed during each 10-year period commencing 10 years prior to the period of extended operation will be in accordance with LR-ISG-2011-03, Table 4a. The extent of coating damage observed during future inspections will be considered when cathodic protection performance requires that piping populations be evaluated as meeting Preventive Action inspection category 'E' or 'F' criteria.

The staff noticed that none of the plants have entered the 10-year period prior to the period of extended operation; and therefore, inspections conducted in the future (e.g., commencing in October 2014 for Byron Unit 1) will be used to determine whether Preventive Action inspection category 'E' or 'F' will be used. The staff finds the applicant's response acceptable because the extent of future inspections will be based in part on the condition of coatings observed during inspections commencing in the 10-year period prior to the period of extended operation, which is consistent with LR-ISG-2011-03 Table 4a. The staff's concern described in RAI B.2.1.28-5a is resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAI B.2.1.28-4, RAI B.2.1.28-5, and RAI B.2.1.28-5a, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which LR-ISG-2011-03 was evaluated.

UFSAR Supplement. LRA Section A.2.1.28, as amended by letter dated January 13, 2014, provides the UFSAR supplement for the Buried and Underground Piping Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1, as revised by LR-ISG-2011-03.

The staff also noticed that the applicant committed to implement the enhancements described above prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Buried and Underground Piping program, the staff determines that those program elements for which the applicant claimed consistency with GALL Report AMP XI.M41 as revised by LR-ISG-2011-03 are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 ASME Section XI, Subsection IWE

Summary of Technical Information in the Application. LRA Section B.2.1.29 describes the existing ASME Section XI, Subsection IWE Program as consistent, with an enhancement, with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE." The LRA states that this program, which complies with ASME Section XI, Subsection IWE, 2001 Edition through the 2003 Addenda, provides for periodic examination of containment structure surfaces and components including bolting for containment closure, containment liner, containment penetrations (electrical instrumentation, and control assemblies), mechanical penetrations, penetration bellows and penetration sleeves at the containment boundary, the personnel airlock and equipment hatch, and the moisture barrier, which is the sealant between the bottom of the containment liner and the concrete base mat. The "scope of program" includes Class metal containment (MC) pressure retaining components and their integral attachments, containment pressure retaining bolting, and MC surface areas, including welds and base metal. The LRA also states that the program utilizes visual examinations (General Visual and VT-3) and augmented inspections (VT-1) for evidence of aging effects that could affect the structural integrity of leak tightness of the containment structure. The LRA further states that Category E-A examination are conducted by a Certified CT-3 examiner or engineer, and Category E-C examinations are conducted by a Certified VT-1 examiner or engineer. Unacceptable conditions are recorded, documented in the CAP, and accepted by engineering evaluation or corrected by repair or replacement.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S1.

The staff also reviewed the portions of "preventive actions" program element associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. LRA Section B.2.1.29 includes an enhancement to the "preventive actions" program element. The applicant stated that the ASME Section XI, Subsection IWE program will provide guidance for specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S1 and finds it acceptable because when it is implemented, it will provide guidance for "preventive actions" to ensure structural bolting integrity, which is consistent with the GALL Report recommendations.

Enhancement 2. LRA Section B.2.1.29, amended by letter dated July 8, 2014, includes an enhancement to the "detection of aging effects" and "monitoring and trending" program elements. The applicant stated that the ASME Section XI, Subsection IWE Program will:

> [u]se the condition of the embedded reinforcing steel at the inner surface of the tendon tunnel as a representative indicator for the potential for corrosion at the exterior surface of the containment liner plate. Use the results of Structures Monitoring (B.2.1.34) aging management program, Enhancement 16 activities and results from ongoing examinations of the tendon tunnel performed as part of the ASME Section XI, Subsection IWL (B.2.1.20) and Structures Monitoring (B.2.1.34) aging management programs to identify changing conditions. Changing conditions consisting of the identification of significant corrosion of embedded steel in the tendon tunnel structure require an evaluation to determine if augmented examination in accordance with requirements of IWE-1240 'Surface Areas Requiring Augmented Examination' are required due to the potential for accelerated corrosion at the exterior surface of the containment liner plate.

The staff reviewed this enhancement and finds it acceptable because when it is implemented, it will link the activities to be performed as part of Enhancement 16 to the Structures Monitoring AMP and the inspections of the containment tendon tunnels conducted in accordance with the Structures Monitoring Program and ASME Section XI, Subsection IWL Program with aging management of the containment liner in accordance with the ASME Section XI, Subsection IWE Program. This will ensure that if there are indications of steel corrosion caused by water infiltration into the containment tendon tunnels, there will be an evaluation to determine whether augmented examinations of the containment liner are required such that the concrete side of the containment liner is adequately managed for loss of material.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S1. In addition, the staff reviewed the enhancement associated with the "preventive actions" program element and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.29 summarizes OE related to the ASME Section XI, Subsection IWE program.

Byron Unit 1. The 2009 ASME Section XI, Subsection IWE Containment Inspection Program examinations identified degraded areas of the moisture barrier. The total length of degraded areas was less than 30 feet over the 440 foot total circumference of the containment liner. The degradation was attributed to damage from traffic on the moisture barrier during outages. The degraded areas were removed to allow for examination of the Containment liner plate below the moisture barrier, and the exposed areas met the IWE acceptance criteria. The moisture barrier was then replaced with new material. The moisture barrier is scheduled to be examined during the current inspection period. Also at Byron Unit 1, the 2012 ASME Section XI, Subsection IWE Containment Inspection Program examinations identified areas where the moisture barrier was degraded. The degraded moisture barrier was removed to allow for examination of the Containment liner plate below the moisture barrier. The exposed liner areas were examined, and it was determined that no coating had ever been applied to those portions of the liner below the moisture barrier. Some material loss due to corrosion was found at the exposed areas. UT examinations were performed at the affected areas and the minimum Containment liner thickness in the exposed areas was 0.2220″ thick, which was evaluated and determined to be acceptable. After examinations, all of the exposed areas were coated with an epoxy Service Level 1 coating. Further examinations of the containment liner plate below the moisture barrier at Byron Unit 1 are planned to ensure all areas below the moisture barrier are coated with an epoxy Service Level 1 coating.

Braidwood Unit 1. Localized areas of corrosion were identified in 2000, during the first ASME Section XI, Subsection IWE examinations of the Containment liner directly below the moisture barrier. All of the moisture barrier and underlying ceramic fiber blanket material was removed to facilitate inspections of the Containment liner. These inspections revealed that the ceramic fiber blanket and adjacent liner area was wet and the original liner coating was degraded. The areas of localized corrosion were evaluated and deemed acceptable. The area was recoated with the same zinc Service Level 1 coating as the original liner coating. The ceramic fiber blanket material and the moisture barrier were replaced. In the subsequent examination period in 2003, augmented liner inspections were performed and areas of localized corrosion not previously identified were found. The inspections found the moisture barrier in good condition with all areas dry under the moisture barrier. UT thickness measurements were taken at areas of localized corrosion. The areas exposed in 2003 were recoated with an epoxy, Service Level 1 coating, and the ceramic fiber blanket and moisture barrier were replaced with new material. Additional inspections were performed (2006, 2009, 2010, and 2012) and found all areas dry, with no active corrosion directly under the moisture barrier. An engineering evaluation was performed in 2009 to determine the cause of the localized areas of corrosion of the liner found in 2003 and subsequent years. This evaluation determined that the most likely cause of liner corrosion prior to implementation of the IWE program was the lack of regular inspection of the moisture barrier; the most likely cause of corrosion after the IWE implementation was an event caused by improper surface preparation of the liner when the zinc rich coating was applied in 1999 and 2000. As of the end of the outage in Spring, 2012, the entire liner in the area under the moisture barrier, which had been coated with zinc rich coating in 2000, had been cleaned and recoated with the epoxy coating.

Similar conditions also occurred at Braidwood Unit 2. The LRA states that plans have been developed to complete the examination of the liner in the area under the moisture barrier which had been coated with zinc rich coating in 2000. The LRA states that these plans include replacement of the zinc rich coating that was applied to the Braidwood Unit 2 liner below the moisture barrier in 2000, with the epoxy coating system, and then to restore the moisture barrier. During the onsite audit, the applicant informed the staff that these activities were completed for Unit 2. The staff also clarified during the audit that the moisture barrier area at both Braidwood Units 1 and 2 are currently subject to augmented examinations in accordance with the ASME Code, Section XI, Subsection IWE.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of RAIs, as discussed below.

During audit walkdowns of the Byron main steam and tendon gallery tunnels, the staff observed white material deposits on the concrete walls and tendon gallery tunnel ceilings, indicative of water leakage or seepage through the containment concrete. Through discussions with the applicant, the staff learned that the cracks through which the material appears to be leaching have existed since initial plant construction. The staff found during its review that on the south side of Byron Unit 1 and north side of Unit 2, the below-grade areas between the main steam tunnels and containment structures were in-filled with limestone during the original construction. According to plant OE, this area has allowed groundwater infiltration to the below-grade containment concrete. The staff noticed that the groundwater at both Byron and Braidwood is considered to be an aggressive environment due to high chloride levels (i.e., greater than 500 ppm).

IWE-1240 states that interior and exterior containment surface areas that are subject to accelerated corrosion, with no or minimal corrosion allowance, require augmented examinations. With the history of aggressive water infiltrating the containment concrete, as evidenced by signs of water intrusion at the tendon gallery ceilings, there is the potential that elevated moisture levels at the outside of the containment concrete could cause moisture to travel through the concrete and come in contact with the carbon steel containment liner. This condition could result in degradation of the containment liner plates caused by accelerated corrosion at exterior surfaces of the containment liner. The applicant had not provided information, based on examination or analysis, on a determination as to whether water has been in contact with the outer surface of the liner or whether there has been any loss of thickness in the carbon steel due to accelerated corrosion, in order to ensure the requirements of IWE-1240 are met. Therefore, by letter dated March 18, 2014, the staff issued RAI B.2.1.29-1 requesting that the applicant state whether there has been (or will be) an evaluation in accordance with IWE to determine (1) if the moisture could come into contact with the liner plate and (2) any resulting loss of material thickness due to corrosion. The staff also requested that the applicant describe how the IWE AMP will be able to ensure that the liner is not degraded such that the leak-tight integrity of the carbon steel is maintained through the period of extended operation.

The applicant responded by letter dated April 17, 2014. The applicant provided information to support its determination that the exterior of the containment liner plate is not an area requiring augmented examination, per IWE-1240; that the water in-leakage issue will be addressed such that the ASME Section XI, Subsection IWE AMP can manage aging of the containment liner through the period of extended operation; and that there is evidence there is no detected loss of material currently at the exterior surface of the containment liner. Specifically, the applicant stated, in part:

> Construction Features: Concrete meeting the requirements of ACI 318 and the guidance of ACI 201.2R with respect to chlorine ion content was used for the

containment concrete in contact with the embedded containment liner. This ensures that contact with the concrete containment will not cause corrosion of the reinforcing steel, liner, liner anchors, or other steel elements embedded in the concrete. In addition, the presence of an abundant amount of calcium hydroxide…gives the water in concrete pore solutions a very high alkalinity with pH of 12 to 13. This pH range is where steel is either thermodynamically 'immune' to corrosion or where a protective passive film is thermodynamically stable on the steel surface…[therefore, steel in contact with the concrete] will not suffer significant corrosion…

> Bounding Environment: The environment (moisture) that exists at the interior side of the tendon tunnel wall…is a bounding environment with respect to the environment that could potentially exist at the concrete containment shell to metal containment liner interface…[because] the tendon tunnel is located 12 feet below the containment liner [and] [t]his configuration results in a higher head of water pressure and establishes a preferential flow path for water infiltrating the concrete at the tendon tunnels, which is below and away from the exterior surface of the containment liner. In addition, the Containment Structure is post-tensioned with hoop and vertical tendons, which close up any shrinkage cracks; therefore the Containment Structure is significantly less permeable with respect to water seepage into the concrete than the tendon tunnels, which are not post-tensioned.

> Representative Indicator: Corrosion of carbon steel is strongly dependent on dissolved oxygen levels. The inside surface of the tendon tunnel is exposed to air, while the…containment concrete shell was placed directly against the containment liner plate, limiting the oxygen available for potential corrosion. Oxygen levels in any moisture that may migrate or diffuse to the containment liner concrete interface are expected to be very low because any moisture in this area would be stagnated, and depleted oxygen levels will not be replenished. As a result, the embedded reinforcing steel at the inner surface of the tendon tunnel is less protected from corrosion than the exterior surface of the containment liner plate. Therefore, the condition of the embedded reinforcing steel at the inner surface of the tendon tunnel can be used as a representative indicator for the potential for corrosion at the exterior surface of the containment liner plate.

The applicant also stated that it is enhancing the Structures Monitoring Program to expose and examine reinforcing steel in the tendon tunnels at locations with water inleakage and mineral deposits to confirm the absence of loss of material due to corrosion of embedded carbon steel. Finally, the applicant's response to RAI B.2.1.29-1 states that there is direct evidence that there is no detected corrosion occurring on the exterior of the containment liner plates because the applicant has performed 21 ultrasonic examinations in the moisture barrier areas and 9 of them were in this area of concern above the tendon tunnels adjacent to the main steam and AFW tunnels.

The staff reviewed the applicant's response and determined that it needed clarifying information regarding the applicant's response. Therefore, during a teleconference call held on May 15, 2014, the staff requested that the applicant clarify whether implementing documents and procedures to conduct the activities described in Enhancement 16 to the Structures Monitoring Program and the ongoing inspections conducted in accordance with the Structures Monitoring Program and ASME Section XI, Subsection IWL Program would specify that indications of rebar corrosion would lead the applicant to evaluate whether augmented examination is needed for the containment liner per the ASME Section XI, Subsection IWE Program. To clarify this, the applicant supplemented its response to RAI B.2.1.29-1.

By letter dated July 8, 2014, the applicant supplemented its response to RAI B.2.1.29-1 to include an enhancement (Enhancement 2) to refer to Structures Monitoring Program Enhancement 16. The applicant stated that "[c]hanging conditions consisting of the identification of significant corrosion of embedded steel in the tendon tunnel structure will require an evaluation to determine if augmented examinations in accordance with requirements of IWE-1240 'Surface Areas Requiring Augmented Examination' are required due to the potential for accelerated corrosion at the exterior surface of the containment liner plate." The applicant's RAI response also included a clarification that the ongoing inspections conducted as part of the activities to monitor water leakage in the tendon tunnel for the Structures Monitoring Program and Enhancement 16 to the Structures Monitoring Program are tied by Enhancement 2 to the ASME Section XI, Subsection IWE Program.

The staff finds the applicant's response to RAI B.2.1.29-1 acceptable because:

- The applicant plans to use the tendon tunnel interior wall as a leading indicator for loss of material of carbon steel, and corrosion detected at the tendon tunnel interior concrete walls will lead to an evaluation to determine if augmented examinations of the containment liner are required
- The lack of significant available dissolved oxygen at the concrete side of the containment liner to concrete interface compared to the interior wall of the tendon tunnel, which is exposed to air, provides reasonable assurance that a lack of rebar corrosion in that area would indicate corrosion of the exterior face of the containment liner is unlikely.
- The applicant is enhancing the Structures Monitoring Program to perform activities that will examine whether corrosion is occurring at embedded reinforcing steel in the tendon tunnel interior wall.
- The applicant has performed UT measurements of the containment liner in nine locations in the area of concern and there have been no indications that there is loss of material at the exterior face of the liner.

The staff's concern described in RAI B.2.1.29-1 is resolved.

The "operating experience" program element in the GALL Report recommends that the ASME Section XI, Subsection IWE program consider OE regarding liner plate and containment shell corrosion. The applicant should demonstrate that it utilizes industry OE in development of the AMP. There is recent industry OE which has indicated that at some plants, the implementation of the IWE program has been ineffective in identifying moisture intrusion into the leak chase channel areas and potential leakage to the containment shell and liner seam welds. This issue is discussed in NRC Integrated Inspection Report 05000348/2012003 and 05000364/2012003 (Joseph M. Farley Nuclear Plant); NRC Integrated Inspection Report 05000395/2011003 (Virgil C. Summer Nuclear Station); and NRC Integrated Inspection Report 05000327/2012005 and 05000328/2012005. Some licensees were not performing general visual examinations of 100 percent of the containment liner plate leak chase systems in accordance with ASME Code Section XI, Subsection IWE requirements, and upon inspection, discovered moisture in the leak chase channel system. Moisture intrusion into the leak chase channel system could reach the containment seam welds. This has the potential to cause corrosion at the welds and affect leak-tightness at the containment or liner pressure boundary. By letter dated March 18, 2014, the staff issued RAI B.2.1.29-2 requesting that the applicant state what actions have been or will be taken to (1) determine whether there is moisture in the leak chase channel area; and (2) ensure the IWE program will be effective in ensuring moisture intrusion and corrosion do not affect the ability of the carbon steel containment liner to perform its function through the period of extended operation.

The applicant responded by letter dated April 17, 2014, and stated that based on this industry experience, action was taken to evaluate the configuration of the leak chase channel system test connections. The evaluation determined that the leak chase channel system test connection configuration at BBS are different from those cited in the industry OE. The RAI response stated that the leak chase channel system test connection pipes at Byron and Braidwood do not end in a pit, rather the pipes extend at least 6 in. above the containment floor. The applicant stated that the leak chase channel system test connection pipes are all capped and have been since initial construction. Therefore, the configuration of the leak chase channel system test connection pipes does not allow water to collect in a pit or moisture to intrude into the leak chase channel system. The applicant further stated that the leak chase channel system test connection pipes and caps are accessible and readily visible, and are inspected as part of the ASME Section XI, Subsection IWE AMP.

The staff reviewed the applicant's response to RAI B.2.1.29-2 and finds it acceptable because (1) the leak chase channel system test connection pipes do not end in a pit; (2) the pipes in the leak chase system that were used to perform the original leak tests and that could allow moisture to reach the containment liner and cause corrosion have been capped since initial construction; (3) the capped pipes are fully accessible and subject to visual examination for loss of material using the ASME Section XI, Subsection IWE AMP. These examinations will manage aging of the capped pipes to ensure that age-related degradation will not affect the ability of the containment liner to perform its intended function during the period of extended operation. The staff's concern described in RAI B.2.1.29-2 is resolved.

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 the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S1 was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.29 provides the UFSAR supplement for the ASME Section XI, Subsection IWE program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancement to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by letter dated July 8, 2014, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its 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 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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, as amended by letter dated July 8, 2014, 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 ASME Section XI, Subsection IWL

Summary of Technical Information in the Application. LRA Section B.2.1.30 describes the existing ASME Section XI, Subsection IWL Program as consistent, with enhancements with GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL." The LRA states that the ASME Section XI, Subsection IWL Program addresses the reinforced concrete and unbonded post-tensioning system of the containment building exposed to air-outdoor and air-indoor (uncontrolled) environments to manage loss of material, cracking, increase in porosity and permeability, loss of bond, and loss of strength through visual examinations, supplemented by testing. The LRA also states that the corrosion protection medium of the tendons is analyzed for alkalinity, water content, and soluble ion concentrations.

The LRA states that the AMP is consistent with the criteria in ASME Code Section XI, Subsection IWL as required by 10 CFR 50.55a. The LRA also states that inspection methods, inspected parameters, and acceptance criteria comply with the 2001 Edition through 2003 Addenda of the ASME Code Section XI, Subsection IWL. The LRA further states that, consistent with 10 CFR 50.55a(b)(2), on each consecutive 120-month inspection interval, the ISI program is updated "to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S2.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.30 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that before the period of extended operation, the AMP will include additional augmented examination requirements in accordance with Table IWL-2521-2 following post-tensioning system repair and or replacement activities. The "parameters monitored or inspected" program element of GALL Report AMP XI.S2 recommends that additional augmented examinations be performed following repair or replacement activities for post-tensioning systems, in accordance with ASME Table IWL-2521-2. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S2 and finds it acceptable because when it is implemented, the ASME Section XI, Subsection IWL Program will include additional augmented examinations for post-tensioning system repair or replacement activities, consistent with the recommendations of GALL Report AMP XI.S2.

Enhancement 2 (Braidwood only). LRA Section B.2.1.30 includes an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated:

> A one-time inspection of one (1) vertical and one (1) horizontal tendon on each unit will be performed prior to the period of extended operation. The inspection will consist of visually examining one (1) wire from each of the two (2) types of tendons at a worst-case location based on evidence of free water, grease discoloration, and grease chemistry results. This location will serve as a leading indicator for potential degradation or tendon surface corrosion (Braidwood only).

LRA Section B.2.1.30 states that "free-water has been found in 3-8 [percent] of the tendon inspections at Braidwood Unit 2…the presence of free water has been consistently detected in specific horizontal, vertical, and dome tendons, and this type of condition has also been detected [at] Braidwood Unit 1." The LRA also states that since Braidwood construction, free water has been found in a "few, specific horizontal and vertical tendon anchorages located below grade." The LRA further states that the water in the dome tendons is due to the degraded dome drainage system and that the water found at vertical tendons and below-grade horizontal tendons is due to the high water table, which is about 20 to 25 feet higher than the bottom of the containment. The LRA states that to address the presence of water in the tendon sheaths, the applicant has performed augmented inspections on additional tendons beyond those selected for the ASME Section XI, Subsection IWL Program. These augmented inspections are performed every 5 years in conjunction with the ASME Section XI, Subsection IWL examinations. In a telephone conference call held on July 30, 2014, the applicant clarified that the use of the word "augmented" with regard to these examinations refers to the applicant's decision to voluntarily exceed the requirements of the ASME Code Section XI, Subsection IWL, and that the referenced examinations are not code-required augmented examinations (ADAMS Accession No. ML14238A092). The LRA also states that due to the history of water found in containment tendons, the applicant included Enhancements 2 and 3 to the ASME Section XI, Subsection IWL Program. The staff's review of Enhancement 3 and the staff's evaluation is documented further in this section of the SER.

The GALL Report states that "the conditions and operating experience at the plant must be bound by the conditions and operating experience for which the GALL program was evaluated, otherwise it is incumbent on the applicant to augment the GALL program as appropriate to address the additional aging effects." The staff noticed that the applicant has augmented and has committed to enhance (Enhancements 2 and 3) its IWL AMP to address its plant-specific OE regarding the historical exposure of tendons to free water at Braidwood. However, the staff has the following concerns:

- For the augmented inspections of additional tendons, performed every 5 years in conjunction with the ASME Section XI, Subsection IWL examinations, it is unclear how the locations for additional tendon inspections will be identified.
- Enhancement 2 proposes a one-time inspection of one horizontal and vertical tendon prior to the period of extended operation. It is not clear what the acceptance criteria will be for the one-time inspection of the corrosion protection medium and tendon wires and what further actions will be taken if the acceptance criteria are not met. Additionally, the enhancement does not include inspection of dome tendons, and the basis for this exclusion is not clear.
- Enhancement 3 states that a followup inspection will be performed within 10 years after the first baseline inspection. The enhancement also states that tendons that do not meet the acceptance criteria during the two previous inspections will be subject to periodic monitoring at a frequency not to exceed 10 years. The staff is unclear as to whether tendons that meet the acceptance criteria during the baseline inspection but do

not meet the acceptance criteria in the followup inspection would be subject to periodic monitoring. For sites with multiple plants, IWL-2421(b) states that when the conditions on IWL-2421(a) are met, the examinations required by IWL-2500 can be performed at a 10-year frequency instead of every 5 years. A 10-year frequency is the maximum frequency (less conservative approach) allowed by the IWL Code for a site with multiple plants. Given the plant's history of water infiltration into the tendon sheaths, the staff needed additional information to support the conclusion that a frequency of examinations not to exceed 10 years will be adequate to manage aging of the tendons.

By letter dated March 18, 2014, the staff issued RAI B.2.1.30-3 requesting that the applicant:

(1) Describe how the locations for augmented inspections of additional tendons will be identified.

(2) Regarding Enhancement 2, state (1) the acceptance criteria for the one-time inspections, (2) what actions will be taken if the acceptance criteria are not met, and (3) the justification for not performing a one-time inspection of the dome tendons.

(3) Regarding Enhancement 3, state (1) what actions will be taken for those tendons where the corrosion protection medium meets the acceptance criteria during the baseline inspection but are found not acceptable during the followup inspection and (2) how the proposed frequency of inspections (not to exceed 10 years) will ensure that possible age-related degradation due to water inleakage to the tendons will be detected in a timely manner and managed such that the tendons will continue to perform their intended functions during the period of extended operation.

By letter dated April 17, 2014, and as supplemented by letter dated July 8, 2014, the applicant provided its response to RAI B.2.1.30-3. The staff's review of the applicant responses to RAI B.2.1.30-3 Requests (1) and (3) are documented in the staff's evaluation of Enhancement 3. The staff's review of the applicant's response to Request (2) follows.

In its response to RAI B.2.1.30-3, Request (2), the applicant stated that the one-time visual inspections of one wire taken from one horizontal and one vertical tendon will be performed in accordance with ASME Code Section XI, Subsection IWL-2523.2. The applicant stated that "[the] acceptance criteria will consist of each wire being free of any active corrosion, including general and pitting corrosion." The applicant also stated that if the condition of the wires does not meet the acceptance criteria it will enter the condition into the plant's CAP. The applicant stated that it will also perform an evaluation to determine the cause, location, corrosion depth, and extent of those conditions that do not meet the acceptance criteria. The applicant further stated that corrective actions will be consistent with those evaluated during the required IWL periodic examinations and may include the following:

> [G]rease analysis, replacement of grease within the tendon duct, additional wire inspections from the same tendon, evaluation of the tendon capacity, potential replacement of the tendon, and augmented inspections and grease sampling of other leading indicator tendons, based, in part, on previous evidence of free water, observed grease leakage, grease discoloration, and grease chemistry results.

Regarding its basis for not performing a one-time inspection of the dome tendons, the applicant stated that the design of the horizontal, vertical, and dome tendons is the same with respect to configuration, tendon sheathing, and protective grease. The applicant stated that, in comparison to the vertical tendons and below-grade horizontal tendons, the instances of significant amounts of free water found in the dome tendons are relatively few. The applicant also stated that due to the location of the dome tendons, above the groundwater table, their exposure to free water has historically been less than that of the vertical and horizontal tendons that are at or below the groundwater table; therefore, the environmental conditions of the vertical and below-grade horizontal tendons bound that of the dome tendons. The applicant further stated that the repair of the containment roof drain system at Braidwood Units 1 and 2 in 2011 and 2012 has reduced the likelihood of future water intrusion into the dome tendons at Braidwood. Therefore, the applicant concluded that "selection of wires from a worst case below-grade horizontal and select vertical tendon will serve as leading indicators for potential degradation or tendon surface corrosion." Based on its review, the staff finds the applicant's response acceptable because:

(1) The applicant defined the acceptance criteria for the one-time inspections of the wires as wires being free of any active corrosion, so the program will identify degradation and evaluate for impact to the structure before a loss of material could affect the tendon intended function.

(2) Conditions that do not meet the acceptance criteria will be entered into the CAP and additional corrective actions will be taken consistent with those corrective actions taken during the required ASME Code Section XI, Subsection IWL periodic examinations.

(3) Selection of tendons from worst-case locations, based on a history of more significant exposure to free water, bounds the environmental condition of the dome tendons and will serve as a leading indicator of potential degradation.

The staff finds this enhancement acceptable because prior to the period of extended operation, the applicant will perform a one-time visual inspection of additional wires (one horizontal and one vertical) beyond the wire examinations required by the ASME Code Section XI, Subsection IWL 2523.1 at a worst case location based on free water and condition of the grease. These visual inspections will be conducted consistent with ASME Code Section XI, Subsection IWL 2523.2 and will allow the applicant to detect age-related degradation of the containment prestressed tendon system before there is a loss of intended function. In addition, conditions indicative of any active corrosion will be entered into the CAP and evaluated in conjunction with the additional activities and corrective actions described in Enhancement 2, as supplemented by letter dated July 8, 2014. This provides reasonable assurance that the effects of aging associated with Braidwood plant-specific tendon water in-leakage will be adequately managed by the ASME Section XI, Subsection IWL Program.

Enhancement 3 (Braidwood only). LRA Section B.2.1.30 includes an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending," program elements. The applicant stated the following:

> In order to monitor for tendon exposure to free water and moisture and manage any potential adverse effects, a periodic tendon water monitoring and grease sampling program will be implemented (Braidwood only). The program will consist of:
>
> (a) A baseline inspection of tendon grease caps at the bottom of all vertical and dome tendons, as well as all below-grade horizontal tendons, prior to the period of extended operation. The baseline inspection will check for

evidence of free water and grease discoloration, with further actions taken based on the condition of the grease.

(b) A followup tendon grease cap inspection of all vertical and dome tendons, as well as all below-grade horizontal tendons, will be performed within 10 years of the initial inspection, using the same approach as the baseline inspection.

(c) For those tendons where free water, moisture, and grease did not meet acceptance criteria during the two previous inspections, periodic monitoring of grease chemistry and moisture, free water, and grease discoloration will be performed on a frequency not to exceed 10 years.

Corrective actions will be taken as necessary to ensure that the tendon grease meets ASME Section XI, Subsection IWL requirements.

As discussed in Enhancement 2, by letter dated March 18, 2014, the staff issued RAI B.2.1.30-3 Requests (1) and (3) to address concerns associated with Enhancement 3.

By letter dated April 17, 2014, and as supplemented by letter dated July 8, 2014, the applicant provided its response to RAI B.2.1.30-3. In its response to RAI B.2.1.30-3, Request (1), the applicant stated that the locations for augmented inspections of additional tendons are identified by the Responsible Engineer. The applicant stated that the augmented tendon locations selected have been on tendons previously examined and found to "exhibit significant quantities (e.g., of more than eight ounces) of free water" and those tendons "nearby and adjacent to ones which have previously exhibited free water." The applicant also stated that the augmented tendon inspections on a 5-year frequency will continue until Enhancement 3 is implemented. Based on its review, the staff finds the applicant's response acceptable because selection of locations for augmented inspections of additional tendons by the Responsible Engineer at or nearby tendons which have previously been exposed to free water provides an opportunity to discover leading indications of potential degradation before there is a loss of intended function. The staff's concern described in RAI B.2.1.30-3, Request (1), is resolved.

In its response to RAI B.2.1.30-3, Request (3) the applicant stated that tendons that meet the acceptance criteria during the baseline inspection but fail to meet the acceptance criteria 10 years later, during the followup inspection, will be subject to additional periodic monitoring. The applicant stated that tendons found with significant quantities of free water will be inspected more often until a frequency is reached such that no significant quantities of free water are observed during successive inspections. The applicant also stated that depending on how grease chemistry and moisture parameters compare to the IWL acceptance criteria the frequency of inspections may vary from 1 to 10 years. The applicant clarified that only the tendons from the sample that (1) have not been inspected for more than 10 years and (2) are found with insignificant quantities of free water and grease discoloration will be inspected at a 10 year frequency. The applicant stated:

> More frequent followup inspections will be performed for tendons which exhibit insignificant quantities of free water, but were inspected within the ten (10) years prior. Any tendons which exhibit significant quantities of free water or grease discoloration will also be inspected more frequently. In all cases, the frequency of inspections for water in individual tendons will be adjusted to be commensurate with the severity of the conditions found during each subsequent examination.

The applicant stated that to-date all ASME Code Section XI, Subsection IWL examination results, and the results of the augmented examination of additional tendons that was performed but was not required by ASME Code Section XI, Subsection IWL requirements, show that the grease (i.e., corrosion protection medium) has been effective in preventing corrosion in tendons exposed to water. The applicant also stated that by increasing the frequency of inspections for, and removal of, free water, the corrosion protection medium (i.e., grease) will continue to provide corrosion protection of the tendons. The staff finds the applicant response acceptable because:

(1) The applicant clarified that any tendons that do not meet the acceptance criteria during the followup tendon grease cap inspection will be subject to additional periodic monitoring of parameters such as amount of free water as well as chemistry, moisture, and discoloration of the grease. The more frequent monitoring of these parameters will provide more information as to the extent of degradation and can inform the corrective actions to be taken, if needed.

(2) The applicant clarified that the frequency of periodic monitoring for the tendons will vary from 1 to 10 years, depending on grease chemistry and moisture parameters of individual tendons; and conditions will be measured against the ASME Code Section XI, Subsection IWL acceptance criteria. Tendons exhibiting more severe conditions will be inspected more frequently, such that degraded conditions can be identified and addressed prior to a loss of structural integrity in the tendon prestressing system.

The staff's concerns described in RAI B.2.1.30-3, Request (3), are resolved. Therefore, RAI B.2.1.30-3 is resolved. The staff finds this enhancement, to address the effects of aging associated with the plant-specific tendon water in-leakage at Braidwood, acceptable because:

(1) The initial and followup inspection of all vertical, dome and below-grade horizontal tendons comprises an overall sample size greater than the maximum required by Table IWL-2521-1 during required periodic ASME Code Section XI, Subsection IWL tendon examinations. Inspection of additional tendons on locations more susceptible to a water environment (e.g., vertical and below grade horizontal tendons) provides reasonable assurance that corrosion in the tendons will be identified before there is a loss of intended function.

(2) The applicant will be performing visual examinations, as well as monitoring for parameters such as quantity of free water, grease discoloration and grease chemistry, which are often leading indicators of potential corrosion in the tendons.

(3) Grease chemistry and moisture parameters will be measured against ASME Code Section XI, Subsection IWL acceptance criteria. If the acceptance criteria are not met, the frequency of periodic monitoring inspections will be increased beyond IWL requirements and corrective actions will be taken to ensure the tendon grease meets ASME Code Section XI, Subsection IWL requirements.

Enhancement 4. LRA Section B.2.1.30 includes an enhancement to the "acceptance criteria" program element. The applicant stated that prior to the period of extended operation, it will require that areas of concrete degradation be "recorded in accordance with the guidance provided in ACI 349.3R." The "acceptance criteria" program element of GALL Report AMP XI.S2 states that IWL-2510 references American Concrete Institute (ACI) 349.3R for guidance regarding identification of concrete degradation. In addition to Enhancement 4, the applicant proposed Enhancement 5, discussed below, to include the quantitative acceptance criteria on ACI 349.3R Chapter 5, “Evaluation Criteria,” to augment the qualitative assessment of the Responsible Engineer. The staff noticed that the proposed enhancements were provided to demonstrate consistency with the recommendations in the GALL Report AMP XI.S2. Based on observations made by the staff during the license renewal inspection at BBS, it was noticed that visual inspections of areas of containment concrete deterioration are made remotely with the use of a telescope. ASME Code Section XI, Subsection IWL allows for remote visual examinations. It also requires that visual examinations be performed in sufficient detail to identify areas of concrete deterioration and distress, such as described in ACI 349.3R. It was not clear what visual resolution capabilities will be used for concrete surface examinations during the period of extended operation to ensure methods and equipment will provide sufficient quantitative measurements to evaluate against the quantitative criteria in Chapter 5 of ACI 349.3R. Therefore, by letter dated November 6, 2014, the staff issued RAI B.2.1.30-6 requesting that the applicant provide information to verify that sufficient visual resolution capability will be used during remote visual examinations of concrete surfaces of containment structures to detect and quantify forms of degradation for comparison against quantitative acceptance criteria based on Chapter 5 of ACI 349.3R.

By letter dated November 21, 2014, the applicant provided its response to RAI B.2.1.30-6. In its response to RAI B.2.1.30-6, the applicant stated that it revised Enhancements 4 and 5 of its ASME Section XI, Subsection IWL Program to ensure that sufficient visual resolution capability will be used to perform remote visual examination of the containment concrete surfaces. The applicant revised Enhancement 4 to add the following statement:

> [t]he visual resolution capability of direct and remote examination techniques will be sufficient to detect concrete degradation at the levels described in Chapter 5 of ACI 349.3R. The resolution capability of the optical aids used for remote examinations will be demonstrated as equivalent to direct visual examination.

Enhancement 5 was revised by the applicant to add the following statement:

> [i]n addition, the Responsible Engineer will confirm that the visual resolution capability used for the concrete [c]ontainment [s]tructure examinations was sufficient to evaluate the examination results against the quantitative criteria acceptance described in Chapter 5 of ACI 349.3R.

The staff confirmed that the applicant revised LRA Section A.1.2.30 (UFSAR Supplement) and LRA Table A.5, Commitment No. 30, consistent with the revisions made to Enhancements 4 and 5. The staff finds the applicant response acceptable because performance of its remote visual examinations during the period of extended operation (Commitment No. 30) will have visual resolution capability that is: (1) demonstrated to be equivalent to direct visual examinations, (2) able to detect concrete degradation consistent with the acceptance criteria of ACI 349.3R Chapter 5, and (3) confirmed by a qualified Professional Engineer (i.e., Responsible Engineer) to be sufficient to assess the condition of the observed concrete against the quantitative acceptance criteria of ACI 349.3R Chapter 5. The staff’s concern described in RAI B.2.1.30-6 is resolved. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S2 and finds it acceptable because when it is implemented, the ASME Section XI, Subsection IWL Program will include explicit requirements to record indications of concrete degradation in accordance with the guidance of ACI 349.3R, which is consistent with the recommendations of GALL Report AMP XI.S2.

Enhancement 5. LRA Section B.2.1.30, as revised by letter dated November 21, 2014, includes an enhancement to the "acceptance criteria" program element. The applicant stated that quantitative acceptance criteria based on Chapter 5, "Evaluation Criteria," of ACI 349.3R will be included before the period of extended operation to augment the qualitative assessment of the Responsible Engineer. The enhancement also states that "the Responsible Engineer will confirm that the visual resolution capability used for the concrete [c]ontainment [s]tructure examinations was sufficient to evaluate the examination results against the quantitative criteria acceptance described in Chapter 5 of ACI 349.3R." GALL Report AMP XI.S2 "acceptance criteria" program element states that quantitative acceptance criteria based on ACI 349.3R Chapter 5 "may be used to augment the qualitative assessment of the Responsible Engineer." The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S2 and finds it acceptable because when it is implemented, the ASME Section XI, Subsection IWL Program will include both qualitative and quantitative acceptance criteria in accordance with the guidance of ACI 349.3R, which is consistent with the recommendations of GALL Report AMP XI.S2.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S2. In addition, the staff reviewed the enhancements associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.30 summarizes OE related to the ASME Section XI, Subsection IWL AMP.

Byron and Braidwood Stations. With regard to NRC IN No. 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments," the applicant stated the following:

> NRC Information Notice IN 99-10, Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments, included observations of containment prestressing system conditions that may precipitate breakage of tendon wires, which were found at the tops of the vertical tendons. […] The conditions at BBS were evaluated and it was determined that the tops of the vertical tendons are not susceptible to breakage of the tendon wires, when compared to those conditions cited in NRC IN 99-10. […] The results of the evaluation at BBS did identify some potential weaknesses in the Containment Structure tendon inspection program. This issue was entered into the corrective action program. Corrective actions were implemented to improve the tendon inspection program. For example, the administrative and implementing procedures for conducting the inservice inspection and testing of the prestressed concrete containment post-tensioning systems were consolidated into a single comprehensive document. In addition, the tendon inservice inspection procedure explicitly directs the responsible engineer to perform and document the regression analysis for the post-tensioning system subjected to physical testing per IN 99-10.

Braidwood Station. With respect to free water found in prestressing tendons the applicant stated the following:

> Free water has been found in 3 to 8 percent of the tendon inspections at Braidwood Unit 2, depending upon the type of tendon. […] The presence of free water has been consistently detected in specific horizontal, vertical, and dome tendons, and this type of condition has also been detected Braidwood Units 1. […] As a result of the presence of free water in the tendon sheaths, Braidwood has performed augmented inspections on additional tendons beyond those selected for the ASME Section XI, Subsection IWL program. The Braidwood augmented inspection is performed on a 5-year frequency, in conjunction with the ASME Section XI, Subsection IWL, and includes grease cap removal, inspection for presence of free water, tendon sheathing corrosion protection medium (grease) and free water chemical analysis, visual inspection for corrosion, and regreasing. […] The historic presence of free water in dome tendons has been due to degraded roof drainage systems at the containment domes. Repairs to the roof drains have been planned and have already been initiated to prevent the accumulation of water on the dome. […] The test results for the pH were all greater than 7 in 2011 for the 21 tendons where water was detected. Active corrosion of the tendons or anchorages has not been identified through the IWL visual inspections, even when water is found in the grease caps and sheaths. […] All of the grease testing to date has met the acceptance criteria in IWL-2525.2 except for instances when the moisture content exceeded 10 percent, at which time, the grease was replaced. […] No tendon failures have been identified at Braidwood. All of the inspection evidence so far reveals that the tendons are being adequately managed, even with the exposure to water.

The staff reviewed OE information in the LRA and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of RAIs, as discussed below.

During its onsite audit at both Byron and Braidwood, the staff reviewed OE regarding suspected areas of degradation in the tendon access gallery tunnel ceilings of the primary containments. The staff noticed that at Braidwood in June 2006 while performing visual examinations of the concrete tendon access gallery tunnel ceilings, 11 locations in Unit 1 and 14 locations in Unit 2 were identified by the applicant as areas with indications of possible degradation. The suspected areas were covered in white deposits and rust. In addition, during the 2006 20th ASME Section XI, Subsection IWL concrete examinations at Braidwood Units 1 and 2, degradation was found in the tendon tunnel ceilings near seven vertical tendon anchorage cans. The degradation consisted of a combination of the following: stalactites, surface concrete cracks, heavy accumulation of minerals, corrosion staining, moisture “wetting,” and accumulation of efflorescence. In 2012, while performing augmented examination of suspect areas identified during the 2011 25th year ASME IWL examinations, conditions similar to those observed in 2006 were found at Braidwood Unit 2. During the onsite audits at both Byron and Braidwood, the staff performed walkdowns of the tendon access gallery tunnels in and noticed suspect areas of degradation similar to those identified by the applicant in 2006, 2011, and 2012 as discussed above. The staff also noticed, through interviews of the applicant staff and review of OE, that both sites exhibit the conditions of concrete degradation at the tendon gallery tunnel ceilings; and at both sites, the groundwater is considered to be an aggressive environment due to high chloride levels (i.e., > 500 ppm). The staff is concerned that some below-grade areas of the concrete containment are exposed to aggressive groundwater, which may be affecting the condition of the concrete. It was not clear whether an evaluation has been performed to assess this condition per the requirements of the IWL Code. The staff needed additional information to determine whether the ASME Section XI, Subsection IWL AMP will be adequate to manage the effects of aging for containment tendon tunnel access gallery concrete. Therefore, by letter dated March 18, 2014, the staff issued RAI B.2.1.30-1 requesting that the applicant state whether the concrete in the tunnel ceiling is subject to chemical attack or leaching. The staff also requested that the applicant provide results of any evaluation conducted or planned to determine the composition of the material (e.g., mineral buildup, white efflorescence) and to evaluate the condition of the concrete at the tendon gallery tunnel ceilings.

In its response dated April 17, 2014, the applicant stated that "[c]oncrete degradation due to chemical attack or leaching has not been observed at the tendon tunnel ceiling concrete at [BBS]." The applicant also stated that chemical attack or leaching is not expected to occur because the groundwater at BBS is not aggressive with regards to pH or sulfates (i.e., pH > 5.5, sulfates <1500 ppm).

The applicant stated that the mineral deposits on the concrete at the tendon tunnel ceilings have not been analyzed for chemical composition; however, an evaluation performed at Byron attributed the source of the mineral deposits to residual material resulting from the evaporation of water in-leakage passing through the dolomite (calcium magnesium carbonate) backfill material. The applicant committed (Commitment No. 34) to obtain mineral deposit samples from locations that exhibit significant mineral deposits in the tendon tunnel and analyze them for chemical composition before the period of extended operation.

The applicant stated that detailed visual examinations of the suspected areas of degradation were performed in accordance with IWL-2500 in 2001, 2006, and 2011 at BBS. The applicant stated that the adverse conditions observed were entered into the CAP and evaluated by the responsible engineer against the acceptance standards in IWL-3000. The applicant also stated the following with regards to its evaluation of the concrete:

> The evaluation of conditions reported resulted in varying degrees of actions taken such as, no action needed, cosmetic repairs of superficial areas to prevent additional or further degradation, additional detailed examinations after cleanup of mineral deposits for further evaluation, and more frequent monitoring. The examinations and evaluations concluded there is no evidence of structural concrete degradation (i.e., no significant cracking, deflection, weakened or softened concrete, or post-tensioning system damage) of the concrete at the tendon tunnel ceilings that would challenge or impact the integrity of the containment structure.
>
> In addition, to further support the above conclusion that groundwater is not causing structural concrete degradation, inaccessible below grade concrete exposed during an excavation was examined and found to be in good condition during an opportunistic examination at Byron.

The applicant stated that the conditions of the tunnel ceiling are bounded by the conditions observed on the interior side of the outer tendon tunnel wall. The applicant also stated that the tendon tunnel wall is subject to a preferential water flow path when compared with the tendon tunnel ceiling because (a) the thickness of the wall is 3 ft while the ceiling is 12 ft, (b) the wall is at a lower elevation (i.e., subject to higher head of water pressure and a preferential flow path), and (c) the ceiling is less permeable with respect to water seepage because it is prestressed by vertical tendons which can close shrinkage cracks. Therefore, the applicant stated that "confirmation activities to demonstrate the condition of the concrete of the tendon tunnel walls can also be used to confirm the condition of the concrete of the tendon tunnel ceiling." The applicant committed (Commitment No. 34) to perform confirmation activities before the period of extended operation as described in Enhancement 16 to the Structures Monitoring Program. The planned confirmation activities include: determination of bounding locations, chemical analysis of water in-leakage and mineral deposits, and removal of three core bores for compressive strength, reinforcing steel, and petrographic examination. The applicant further stated that adverse findings will be entered into the CAP. The staff's evaluation of the applicant's planned confirmation activities is documented in SER Section 3.0.3.2.20 with the evaluation of the Structures Monitoring Program.

The staff finds the applicant's response to RAI B.2.1.30-1 acceptable for the following reasons:

(1) The applicant stated that concrete degradation due to chemical attack or leaching has not been observed and the groundwater at BBS is nonaggressive with respect to pH and sulfates.

(2) The applicant committed to obtain mineral deposit samples and analyze them to determine its chemical composition before the period of extended operation.

(3) The applicant has evaluated the concrete and concluded that the source of the mineral deposits is residue of the evaporation of water in-leakage passing through the backfill material and not the concrete. The applicant identified the areas of suspect degradation, performed detailed visual inspections of the conditions in accordance with IWL-2500, took corrective actions, evaluated the conditions in accordance with IWL-3000, and concluded that there is no evidence of concrete degradation that would impact the integrity of the containment structure. The applicant also committed to remove three core bores before the period of extended operation in order to test the concrete compressive strength and perform a petrographic examination. The applicant will also expose reinforcing steel to examine the condition.

(4) Based on its review of the applicant's response and the staff's observations of the conditions in the concrete tendon tunnel ceiling and walls during walkdowns of the tendon tunnel galleries at BBS, the staff finds that the conditions of the tunnel ceiling are bounded by the conditions observed on the interior side of the outer tendon tunnel wall. The staff finds that activities performed to evaluate the mineral deposits and condition of the concrete at the tendon tunnel wall can be used to confirm the condition of the concrete and composition of the mineral deposits at the tendon tunnel ceiling.

The staff's concern described in RAI B.2.1.30-1 is resolved.

Concrete Dome Degradation (Braidwood Units 1 and 2). During its review of BBS OE, the staff noticed that suspected areas of concrete degradation have been identified during the ASME Section XI, Subsection IWL inspections in 2006 and 2011 at Braidwood Units 1 and 2. The staff also noticed that inspections have revealed the sealant and cover of drainage system drain assemblies to be significantly degraded or missing in the dome area of the containments. The staff noticed that the applicant's condition report stated that the concrete degradation may be associated with deterioration of the drainage system at Braidwood. As documented by the applicant, the following conditions have been observed in the concrete surrounding the dome drains: separation, chips, and loose concrete; accumulation of white deposits or efflorescence on concrete surfaces; accumulation of water; “minor” spalls; cracks (one reported as being more than 6 in. long and 0.8 in. wide at the concrete surface); and corrosion staining. The staff is concerned that the observed conditions of the concrete near the dome drains may be indicative of, or may result in, degradation. In addition, accumulated water could migrate through the cracks and reach the rebar causing corrosion. The staff needs additional information regarding the condition of concrete in suspected areas of degradation and methods of evaluation to assess whether the effects of aging will be adequately managed during the period of extended operation. Therefore, by letter dated March 18, 2014, the staff issued RAI B.2.1.30-2 requesting that the applicant state whether actions have been taken or are needed in order to adequately evaluate concrete degradation and implement mitigating actions to prevent loss of intended function during the period of extended operation. The staff also requested the applicant to provide a summary of actions taken to correct the degraded condition of the dome drainage system in order to prevent the accumulation of water in the suspected areas of concrete degradation.

In its response dated April 17, 2014, the applicant stated that the accumulation of calcium deposits (efflorescence) were identified near the concrete dome surfaces of all six drain lines while performing the 2011 25th year post-tensioning surveillance and augmented examinations at Braidwood Units 1 and 2. The applicant stated that after the efflorescence was removed, it performed detailed visual examinations which revealed a maximum measured crack width of 0.080 in. at the concrete surface that narrowed to a width of 0.015 in. at a depth of no more than 0.125 in. The applicant also stated that it documented the cracking in the CAP; however, a typographical error was introduced when the cracking was initially documented as having a width of 0.80 in. at the concrete surface. The applicant attributed the efflorescence to leakage of the containment dome drain piping and sleeve. The applicant stated that the cracks have no impact on the containment structure because the 2006 and 2011 inspections revealed the cracks to be consistent, there is no exposed reinforcing steel, and there was no evidence of reinforcing steel corrosion, spalls that would indicate corrosion of the concrete rebar or shifting of concrete due to cracking. The applicant further stated that it performed examinations of the concrete cracks around the drainage pipes in August 2012 and 2013 and no additional degradation was identified in those areas. The applicant stated that the concrete surrounding the dome drains is sound and the observed conditions do not indicate age-related degradation. The applicant also stated that it will continue to monitor the cracking near the drain piping under the ASME Section XI, Subsection IWL Program. With regard to the degraded condition of the dome drainage system, the applicant stated that actions have been taken under the CAP, and the degraded conditions were repaired by January 2012. The applicant also stated that it performed followup inspections in August 2012 and 2013 to verify the effectiveness of the repair, and no additional degradation was identified in the dome drainage system. The applicant further stated that there are no further actions required by the ASME IWL Code and that it will continue to monitor the condition of the dome drains through periodic inspections as part of the Structures Monitoring and ASME Section XI, Subsection IWL Programs.

The staff finds the applicant’s response acceptable because:

(1) The applicant performed detailed visual examinations of the identified areas of concrete deterioration in accordance with IWL 2310(b) and documented the cracking in its CAP. The maximum crack has a width of 0.08 in. at the surface that narrows to 0.015 in. at a depth of 0.125 in. Examination of the cracks in 2006 and 2011 revealed no change in the cracks, no evidence of exposed reinforcing steel or rebar corrosion, and more recent inspections in 2011 and 2013 found no additional degradation. The results of this

evaluation indicate the condition of the concrete is within the first tier criteria of ACI 349.3R.

(2) The applicant repaired the degraded condition of the dome drainage system and followup inspections in August 2012 and 2013, both of which did not identify additional degradation of the dome drainage system or surrounding concrete.

The staff's concern described in RAI B.2.1.30-2 is resolved.

Concrete Containment External Surface Rust Stain (Braidwood Unit 2). During its audit, the staff performed a walkdown to observe the exterior surfaces of the concrete containments at Braidwood Units 1 and 2. During the walkdown, the staff noticed a vertical line of rust staining on the south face of the Unit 2 containment. The GALL Report AMP XI.S2 states that in accordance with ASME Code Section XI, Subsection IWL-2510, concrete surfaces are to be examined for conditions indicative of degradation as defined in ACI 201.1R, "Guide for Conducting a Visual Inspection of Concrete Surfaces," and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." The staff noticed that ACI 201.1R and ACI 349.3R identify rust staining as a condition indicative of active corrosion of iron-based material that is taking place internally in the concrete or externally on the surface of the structure. From review of Braidwood OE and interviews with the applicant personnel during the audit, it was not clear (1) what was causing the rust staining, (2) whether the condition is indicative of age-related degradation, and (3) how the condition is addressed under the ASME Section XI, Subsection IWL Program. The staff needed additional information to complete its review. Therefore, by letter dated March 18 2014, the staff issued RAI B.2.1.30-4 requesting that the applicant (1) identify the cause of the rust stains, (2) state whether there are aging effects associated with the rust stains, and (3) state whether the rust stains have been evaluated and will be monitored under ASME Code Section XI, Subsection IWL-2510.

In its response dated April 17, 2014, the applicant stated that:

(1) The cause of the discoloration stains on Braidwood Unit 2 containment is the loss of material of form ties and nails used as construction aids that remained exposed on the external surface of the containment.

(2) These components are not associated with SSCs that perform a license renewal intended function. The 2001, 2006, and 2011 IWL concrete examinations of the area determined that the concrete is intact and there are no indications of cracking with outward displacement or incipient spalls that would suggest the discoloration stains are due to corrosion or degradation of reinforcing steel. Also, there has been no appreciable change in the vertical line of discoloration staining.

(3) The exterior surface of the concrete containment is examined every 5 years and evaluated in accordance with ASME Code Section XI, Subsection IWL-2510. The applicant further stated that rust staining is a condition identified during visual examinations and as a result these areas of discoloration have been visually inspected and evaluated every 5 years during IWL examinations and will continue to be monitored every 5 years in accordance with ASME Code Section XI, Subsection IWL-2510. The applicant stated that based on the IWL visual inspections and evaluations of the areas of discoloration there's no evidence of structural degradation sufficient to warrant further evaluation or repair.

The staff finds the applicant's response acceptable because the applicant evaluated the condition and determined that there are no indications that suggest that the rust is a result of age-related degradation of the concrete or reinforcing steel and the area has been and will continue to be inspected for age-related degradation during containment ISIs in accordance with the ASME Code Section XI, Subsection IWL through the period of extended operation. The staff's concern described in RAI B.2.1.30-4 is resolved.

Through Crack Grease Leakage in Steam Generator Concrete Patch (Byron Unit 1). During its onsite audit, the staff reviewed OE regarding a diagonal crack with grease leakage on the Braidwood Unit 1 containment. The crack was located on the upper right corner of an area of concrete that was repaired after the Braidwood Unit 1 primary containment concrete was cut out for the steam generator replacement in 1998. The crack was found in 2006 during the 25th ASME Section XI, Subsection IWL visual inspection of the containment concrete. During a walkdown at Braidwood, the staff noticed that there was also a similar crack on the upper left corner of the steam generator replacement patch. The staff reviewed a letter dated February 26, 2008 (ADAMS Accession No. ML080570644), that was submitted to the staff by the applicant, which stated that the condition was evaluated for Braidwood Unit 1 and was determined to be acceptable because the amount of grease leakage was small. The letter also stated that the grease leakage is being monitored on an annual basis, during the summer months when the sheathing filler viscosity results in the worst-case condition for leakage. During the onsite audit, the applicant stated that a similar condition exists for the Byron Unit 1 primary containment concrete at the steam generator replacement patch. The applicant did not provide information to indicate that the cracks at Byron have been evaluated. The staff needed additional information to determine (1) whether more rigorous detailed visual examinations of the cracks were required or performed, and (2) whether the grease leakage from the cracks is evaluated per the IWL Code to determine whether an adverse condition has occurred with the prestressed tendons in that location. Therefore, by letter dated April 7, 2014, the staff issued RAI B.2.1.30-5 requesting that the applicant describe any actions taken, the type and frequency of inspections performed, and any corrective actions performed or planned to address the cracking in accordance with the ASME Section XI, Subsection IWL Program. The staff also requested that the applicant state whether there has been an evaluation per the IWL Code to assess the amount of grease leakage coming through the cracks and to determine if the leakage has any adverse effect on the ability of the affected tendons to perform their intended function.

In its response dated May 6, 2014, the applicant stated that concrete surfaces are subject to general periodic (5-year frequency) visual examination to detect signs of deterioration as defined in ACI 201.1R and ACI 349.3R and the crack and grease leakage in question have been examined on four occasions (1998, 2001, 2006, and 2011) and will continue to be examined in accordance with ASME Section XI, Subsection IWL and ACI 349.3R.

The applicant stated that the cracks at Byron Unit 1 were identified in 1998 during examination of the containment following the replacement of the steam generators and were described as 0.01 in. wide diagonal shrinkage cracks at the corners of the square patch. The applicant stated that detailed visual examinations of the cracks were performed before, at peak pressure, and at the conclusion of the integrated leak rate test (ILRT) that pressurized the containment following the steam generator replacement in 1998. The applicant also stated that during the ILRT, it noted and mapped the extent, width, location, and lengths of the cracks; an evaluation of the ILRT results determined the cracks to be insignificant. During the 2001 IWL general visual examinations, the cracks and grease leakage were recorded and corrective actions were taken, which included followup examinations, entrance of the condition into the IWL program records for followup examinations, and an evaluation by the Responsible Engineer. Followup IWL general visual examinations of the containment performed in 2006 and 2011 identified no significant changes to the cracks or grease leakage deposits and described the shape and size of the grease leakage deposits as unchanged. The applicant stated that the Responsible Engineer evaluated the cracks and grease leakage deposits in 2001, 2006, and 2011 and determined that the conditions were not structurally significant with respect to containment structural integrity. The applicant stated that the cracks are acceptable without further evaluation because they are passive and less than 0.015 in. in width and, therefore, meet the tier 1 criteria in ACI 349.3R.

The applicant also stated that the grease leakage through the cracks amounts to only a few ounces of grease and does not indicate that an adverse condition has occurred with the prestressed tendons at the patch. The applicant further stated that during its 20th year (2004) containment tendon examination, it physically examined two hoop tendons and one vertical tendon affected by the steam generator replacements and "[a]ll acceptance criteria were met and there were no indications of degradation detrimental to containment structural integrity associated with the cracks or grease leaks." The applicant also stated the following:

> To date, only small volumes of deposits from grease leakage have been identified, these have been quantified and do not appear to be increasing over time. The grease deposits are trended so that any change or increase will be noted during examinations and evaluated by the [Responsible Engineer] to determine if there is any indication of degradation that would be detrimental to containment structural integrity. The grease leakage is no longer active and the volume of the grease leakage deposits were estimated to be only a few ounces, which is insignificant compared to the net volume inside the tendon sheath of approximately 100 gallons. These conditions are considered to meet the acceptance criteria in ASME Section XI, Subsection IWL-3221.4, "Corrosion Protection Medium," which states that protection medium is acceptable when the absolute difference between the amount removed and the amount replaced shall not exceed 10 [percent] of the tendon net duct volume.

The staff finds the applicant's response acceptable because:

(1) The applicant performed general visual examinations of the concrete surfaces in 1998, 2001, 2006, and 2011 and was able to identify the areas of concrete deteriorations (cracks and grease leakage deposits) in accordance with IWL-2310(a). A detailed visual examination of the condition was performed in 1998 in accordance with IWL-2310(b) during the ILRT and an evaluation of the results by the Responsible Engineer determined the cracks to be insignificant. In accordance with IWL-2320 and IWL-3300, the crack and grease leakage were evaluated in 1998, 2001, 2006, and 2011 by a qualified Responsible Engineer, and the conditions were determined to be insignificant with respect to structural integrity of the containment. The Responsible Engineer found no significant changes of the cracks or grease leakage deposits in 2006 and 2011. In addition, the cracks are passive and less than 0.015 in. wide which meets the tier 1 criteria in ACI 349.3R and therefore are acceptable without further evaluation.

(2) The applicant stated that the tendon net duct volume is approximately 100 gallons. The applicant has quantified and trended the volume of grease leakage deposits and determined that the grease leakage deposits to date amount to a few ounces which does not exceed 10 percent of the tendon net duct volume and therefore meets the

acceptance criteria in IWL-3221.4. In addition two hoop tendons and one vertical tendons in the location of the steam generator patch were physically examined during the 20th year (2004) ASME Code Section IX, Subsection IWL containment tendon examination and the tendons met all the acceptance criteria.

The staff's concern described in RAI B.2.1.30-5 is resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAIs B.2.1.30-1, B.2.1.30-2, B.2.1.30-3, B.2.1.30-4, B.2.1.30-5, and B.2.1.30-6, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S2 was evaluated.

UFSAR Supplement. LRA Section A.2.1.30, as revised by letter dated November 21, 2014, provides the UFSAR supplement for the ASME Section XI, Subsection IWL Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed (Commitment No. 30) to implement the enhancements to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its 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. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 ASME Section XI, Subsection IWF

Summary of Technical Information in the Application. LRA Section B.2.1.31 describes the existing ASME Section XI, Subsection IWF Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF."

The LRA states that the AMP addresses ASME Section XI Classes 1, 2, 3, and MC piping and component support members exposed to air-indoor uncontrolled, air-outdoor, air with borated water leakage, and treated borated water to manage the effects of aging. For these components, the program uses periodic visual examination to detect signs of degradation such as loss of material, loss of mechanical function, and loss of preload. Bolting for component supports is included with the component supports and inspected for loss of material and loss of preload by inspecting for missing, detached, or loosened bolts and nuts.

The ASME Section XI, Subsection IWF Program is implemented through corporate and station procedures, and complies with the ASME Code, Section XI, Subsection IWF as required by 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 compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S3.

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

The "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements in GALL Report AMP XI.S3 specify recommendation for aging management of high-strength bolts as follows:

(1) The "preventive actions" program element of GALL Report AMP XI.S3 recommends that high-strength bolting material not be used in structural bolting applications, and rather, that bolt material used should have an actual measured yield strength less than 150 ksi. The GALL Report also recommends that for structural bolting consisting of ASTM A325, ASTM F 1852, and/or ASTM A490 bolts, that the program should follow the preventive actions for storage, lubricants, and SCC potential discussed in Section 2 of Research Council on Structural Connections (RCSC) publication "Specification for Structural Joints Using ASTM A325 or A490 bolts."

(2) The "parameters monitored or inspected" program element of GALL Report AMP XI.S3 recommends that high-strength structural bolting susceptible to SCC be monitored for SCC.

(3) The "detection of aging effects" program element of GALL Report AMP XI.S3 recommends that, for high-strength structural bolting in sizes greater than 1 in. nominal diameter, volumetric examination should be performed in addition to the VT-3 examination to detect cracking, and that this volumetric examination may be waived with adequate plant-specific justification.

During its onsite audit of the ASME Section XI, Subsection IWF AMP, the staff noticed that the AMP states IWF supports at BBS do not use high-strength bolts susceptible to SCC. However, during its review of the UFSAR and discussions with the applicant onsite, the staff noticed that there may be high-strength bolting (i.e., ASTM A490) in sizes greater than 1″ diameter and actual yield strength greater than 150 ksi that is applicable to the IWF AMP but that was not considered for SCC potential. The staff needed additional information to complete its review. Therefore, by letter dated February 7, 2014, the staff issued RAI B.2.1.31-1 requesting that the applicant identify whether there are high-strength structural bolts in the scope of the IWF program that were not previously identified for aging management for cracking due to SCC and, if so, to describe how the program will manage aging of these components in accordance with the GALL Report recommendations.

In its response dated March 4, 2014, the applicant stated that there are high-strength ASTM A490 structural bolts greater than 1-in. diameter used for ASME Class 1 component supports. The applicant also stated that the ASME Section XI, Subsection IWF AMP is revised to follow the recommendations of the GALL Report AMP XI.S3 for the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements.

For the "preventive actions" program element, the applicant stated that it will:

(1) Revise implementing documents to provide guidance for specification of bolting material, storage, lubricants and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Bolting material with actual measured yield strength of 150 ksi or greater will not be used without engineering approval.

(2) Revise implementing documents to specify storage requirements for high-strength bolts that include the RCSC specifications.

(3) Revise implementing documents to specify that lubricants that contain molybdenum disulfide (MoS_2) shall not be applied to high-strength structural bolts within the scope of license renewal.

With regards to this program element, the staff issued RAI B.2.1.31-2, which describes the staff's concern for the future use of MoS_2 on high-strength structural bolting in the IWF program. The staff noticed that both the responses to RAI B.2.1.31-1 and B.2.1.31-2 confirm that the program is enhanced to prohibit use of lubricants containing MoS_2 for structural bolting within the scope of license renewal. This is discussed further in the staff's review of Enhancement #2 below.

For the "parameters monitored or inspected" program element, the applicant stated that the program will be enhanced (Enhancement #5) to monitor parameters to detect a corrosive environment that supports SCC potential for high-strength bolting greater than 1-in. nominal diameter. The applicant stated that the periodic visual inspections will look for evidence of moisture, residue, foreign substance, or corrosion to identify if bolting has been exposed to moisture or other contaminants.

For the "detection of aging effects" program element, the applicant proposed that plant-specific history on volumetric examination of high-strength bolts greater than 1-in. nominal diameter and periodic visual examinations to detect a corrosive environment is used to justify taking exception to the GALL Report for volumetric examinations. The applicant added Enhancement #4 stating that for ASTM A490 bolts, it will perform volumetric examinations of 20 percent of the ASTM A490 bolts greater than 1-in. diameter or a maximum of 25 bolts, inclusive for both BBS. The applicant also stated that any adverse results of the volumetric examinations will be entered into the CAP and will be evaluated to determine if additional actions are warranted "such as expansion of sample size, scope and frequency of any additional supplemental visual or volumetric examinations, as well as requirements specified by ASME Section XI, Subsection IWF."

The staff reviewed the applicant's response to RAI B.2.1.31-1 and found it partially acceptable because:

- The applicant has appropriately identified high-strength structural bolting in the IWF program to include high-strength ASTM A490 bolting in sizes greater than 1-in. diameter.
- Consistent with recommendations in the GALL Report for ensuring bolting integrity, implementing documents for the IWF program will be revised to:
    - Provide guidance for specification of bolting material storage, lubricants and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolts.

- Provide guidance such that bolting material with actual measured yield strength of 150 ksi or greater will not be used in the plant without engineering approval.
- Specify storage requirements for high-strength bolts that include the recommendations of the RCSC, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," Section 2.
- Specify that lubricants that contain MoS_2 will not be applied to high-strength bolts within the scope of license renewal.

- The applicant's performance of one-time volumetric examinations on ASTM A490 bolts to detect SCC provides adequate plant-specific justification to waive volumetric examinations of these high-strength structural bolts.

However, the staff needed additional information regarding some aspects of the applicant's response and associated Enhancement #4 to the IWF Program to complete its review. The staff noticed that ASME IWF-2430 contains requirements for the performance of additional examinations when VT-3 visual examinations reveal flaws or relevant conditions that exceed the acceptance standards of IWF-3400. However, the volumetric examinations that will be performed on high-strength bolts to support a plant-specific exception to the GALL Report are not specifically called out in, nor specifically subject to, the requirements of IWF-2430 for additional examinations. The applicant's ASME Section XI, Subsection IWF Program has not established criteria for expansion in inspection scope for these components in the case of adverse results of volumetric examinations. The staff determined that it needed additional information regarding whether procedures for performing this one-time examination will include criteria for expansion of scope, consistent with the methodology of ASME Code Subsection IWF. The staff determined that it also needed additional information to clarify, if the one-time volumetric examinations show signs of cracking, whether the IWF Program would be revised to include periodic volumetric, instead of visual, examinations.

Therefore by letter dated May 22, 2014, the staff issued RAI B.2.1.31-1a requesting that the applicant (1) state whether the one-time volumetric examinations planned, on a sampling basis to support an exception to GALL Report recommendations, will be subject to criteria for expansion of inspection scope, similar to the methodology used by the ASME Code for IWF components; and (2) if the one-time volumetric examinations show signs of cracking, state whether the program would be revised to include periodic volumetric examinations or provide supporting technical basis for not performing volumetric inspections on a periodic basis.

The applicant's responded to RAI B.2.1.31.1a by letter dated June 16, 2014. The applicant stated that the "ASME Section XI, Subsection IWF aging management program will establish criteria for expanding the inspection scope for [ASTM A490 bolts] in the case of adverse results of the one-time volumetric examinations similar to the methodology used by the ASME Code IWF-2430 for IWF component supports." The applicant stated that the implementation of the one-time inspection will include a provision that requires an expansion in scope to other ASTM A490 bolts that are in the same joint configuration and exposed to similar environments in case(s) of adverse results in the one-time volumetric examinations. The applicant also stated that if cracking is detected during the one-time inspection of ASTM A490 bolts, the program will be revised to include periodic volumetric examinations of ASTM A490 bolts. The applicant stated that these examinations "are included in the periodic examination of the supports. For the periodic examinations, the population of the supports examined is specified in Table IWF-2500-1."

The staff reviewed the applicant's response to RAI B.2.1.31-1a and found it partially acceptable because:

- The applicant will use criteria similar to that of IWF-2430 for expansion of inspection scope to other bolts if the one-time volumetric examinations show signs of cracking.
- If the one-time volumetric examinations show signs of cracking in ASTM A490 bolts, the ASME Section XI, Subsection IWF Program will be revised to include periodic volumetric examinations, which is consistent with GALL Report recommendations.

The staff noticed that when the program is revised to include volumetric examinations in the case that the one-time inspections show signs of cracking, the applicant stated that the ASTM A490 bolts that would be subject to volumetric examination are "included in the periodic examination of the supports." The staff needed additional information to determine whether there is a sufficient number of ASTM A490 bolts on IWF supports in the IWF inspection sample to be representative of the aging of the entire population of high-strength A490 bolts in IWF supports in the plant. Therefore, in a teleconference held on July 15, 2014, the staff requested that the applicant clarify how the sample of A490 bolts will be selected when the program is revised to include volumetric examinations in the case that the one-time inspections show signs of cracking (ADAMS Accession No. ML14202A396). The applicant stated that all of the high strength ASTM A490 bolts are on ASME Class 1 supports, i.e., the steam generators, reactor coolant pumps (RCPs), and the pressurizer, for each unit at BBS. The applicant further stated that per the IWF code, the supports for one steam generator, one RCP, and the pressurizer are inspected at 10 year intervals for each unit at both Byron and Braidwood and that 100 percent of the accessible bolts are inspected at each of these locations. That represents approximately 25 percent of the high strength ASTM A490 bolts for each unit, since all units are 4-loop PWRs. The staff considered this clarification, and finds it acceptable that, when the program is revised to include volumetric examinations of high strength ASTM A490 bolts in the case that the one-time inspections show signs of cracking, it is acceptable to perform those volumetric examinations on the bolts that are already included in the periodic IWF examinations of the corresponding supports. The staff's concern in RAI B.2.1.31-1a is resolved.

During the 71002 inspection at Byron Station, the staff identified that the applicant had not included the CRDM seismic support assembly in the scope of license renewal for BBS. The applicant determined that these components were required to be within the scope of license renewal. By letter dated August 29, 2014, the applicant revised the LRA to include an enhancement to the ASME Section XI, Subsection IWF program to include examinations of these components. The applicant stated that the components "will be managed by performing VT-3 examinations in accordance with the ASME Section XI, Subsection IWF program requirements for Class 1 component supports during every ten (10) year ISI inspection interval." The applicant also revised LRA Table 3.5.2-3 to include the CRDM support components in the AMR tables. The revised LRA stated that these supports include carbon and low-alloy steel (LAS) bolting exposed to an air with borated water leakage environment. The staff reviewed the LRA revisions and could not determine whether steel bolting included high-strength bolting. The staff needed additional information to determine whether the bolting would be adequately age-managed. Therefore, by letter dated October 9, 2014, the staff issued RAI B.2.1.31-4, requesting that the applicant state whether high-strength bolts with an actual measured yield strength greater than or equal to 150 ksi in sizes greater than 1″ are used in CRDM seismic supports. The staff requested that, if so, the applicant provide additional information on the type and grade of the material and explain how visual inspections will be adequate to detect cracking due to SCC.

By letter dated October 16, 2014, the applicant responded to RAI B.2.1.31-4, stating that "there are no high strength bolts (actual measured yield strength greater than or equal to 150 ksi) in sizes greater than 1 [in.] used in the CRDM supports." The applicant stated that therefore, SCC is not postulated. The staff reviewed the applicant's response and finds it acceptable because the GALL Report states that for non–high strength bolting used in ASME Section XI, Subsection IWF applications, visual VT-3 examinations are adequate to manage aging for all identified aging effects and that SCC is not an applicable aging effect for these bolts. The staff's concern in RAI B.2.1.31-4 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," "detection of aging effects," and "monitoring and trending" program elements associated with exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B.2.1.31 includes an exception to the "preventive actions" program element. The applicant states that the GALL Report recommends using bolting material for high-strength structural applications that have an actual measured yield strength limited to less than 150 ksi. The applicant further states that site documentation indicates that the originally installed 5″ diameter RCP hold-down bolts at both Byron and Braidwood have actual measured yield strength of 150 ksi and the 1-1/2″ diameter pressurizer hold-down bolts at Braidwood have actual measured tensile strength of 170 ksi or greater. The staff noticed that Exceptions 1 and 2 are very closely related, so the discussion of further information provided by the applicant and the staff's review will encompass both Exceptions in the staff's evaluation for Exception 2.

Exception 2. LRA Section B.2.1.31 includes an exception to the "detection of aging effects" program element. The applicant states that the GALL Report recommends volumetric examination of high-strength bolting material with a diameter of greater than 1″ and used in structural applications, which have a measured yield strength greater than or equal to 150 ksi. The LRA states that there are no qualified standards to perform volumetric examinations on these high-strength bolts at BBS.

The LRA states that these bolts were consistent with the existing ASME Code design guidance when installed and are relatively immune to SCC. The LRA also states that other preventive measures were taken, including not using metal-plated stud bolting, and using an approved stable lubricant that did not contain MoS_2. The applicant stated that the bolts are not exposed to an environment that would initiate SCC so there is no need to perform volumetric examinations in accordance with the GALL Report recommendations. The applicant also states that the bolts are configured such that there is no potential for borated water to come into contact with the bolt threads. The applicant stated that it will use plant-specific justification to not perform volumetric examinations of the ASTM SA 540 RCP hold-down bolts at BBS and the pressurizer hold-down bolts at Braidwood.

The applicant stated that the bolts are not susceptible to SCC because:

(1) The bolt design is in a configuration that precludes water from penetrating the interface between the bolt head and support surface and seeping beneath the bolt head, which prevents the potential initiation of corrosion. The bolts were torqued to bear tightly on the support surface.

(2) Metal plated stud bolting is not used, which could cause degradation due to corrosion or hydrogen embrittlement.

(3) An approved lubricant was applied to the bolts; this lubricant did not contain MoS_2.

(4) There have been no recordable indications of degradation identified by ASME Section XI, Subsection IWF program examinations that would indicate the potential for SCC to occur.

The staff reviewed the applicant's plant-specific justification to waive volumetric examinations of the RCP hold-down bolts and pressurizer hold-down bolts and the applicant's plan to use visual examinations alone to manage aging of these components. Specifically, the staff is concerned that the ASME Section XI, Subsection IWF AMP basis documents state that the RCP hold-down bolts are located in an "air with borated water leakage" environment. Since there is a potentially moist environment, susceptible material, and stress present to cause SCC, GALL Report AMP XI.S3 recommends that high-strength bolting in size greater than 1″ should be managed for SCC. An onsite audit of the design drawings for the bolt configuration determined that there is no physical seal preventing water intrusion beneath the bolt head. The staff did not have enough information to accept the applicant's basis that the surface between the bolt head and support surface is watertight and that cracking due to SCC is not possible. The staff noticed that the applicant's previous experience with the IWF program indicates that cracking due to SCC has not been found to be a degradation mechanism. However, since the IWF examination does not include volumetric examination for cracking beneath the bolt head for high-strength structural bolts greater than 1″ diameter, the OE referenced by the applicant does not preclude the potential for SCC for these components. The staff also had concerns regarding the criteria and actions to be taken (i.e., similar methodology as is used by ASME IWF) for expansion of scope, increase in inspection frequency, or performance of visual examinations, if there are indications from periodic visual inspections that SCC could be occurring. This concern and its resolution is discussed previously in this SER section.

By letter dated February 7, 2014, the staff issued RAI B.2.1.31-3 requesting that the applicant provide the results of any plant-specific history of volumetric examination of high-strength bolts in a similar environment. The staff requested that (1) if there is no history of volumetric examination of the referenced bolts, then the staff requested the applicant state whether any volumetric examinations (or alternative method) will be conducted prior to the period of extended operation to confirm that cracking due to SCC has not affected the bolt threads; (2) state what parameters or criteria will be used to detect SCC or a corrosive environment and how visual inspections will be effective in detecting future SCC; and (3) state what actions will be taken with respect to augmented examinations if inspections result in indications that there is degradation or a corrosive environment that could lead to SCC, including any plans for supplemental volumetric examinations.

The applicant responded to RAI B.2.1.31-3 by letter dated March 4, 2014. The staff identified that the applicant's response covered four main points, and has numbered the four points for clarity. The applicant's response to RAI B.2.1.31-3 stated, in part, that:

(1) Byron and Braidwood have an extensive history of volumetric examinations of the unpainted reactor head closure studs, which use the same ASME SA 540 material as the RCP hold-down bolts and pressurizer hold-down bolts. One hundred percent of these bolts have been subject to volumetric examination at 10-year intervals, and no evidence of SCC has been identified. Because of the similar materials and environmental conditions, the reactor head closure stud volumetric examinations can be

used to support an exception to the GALL Report recommendations for periodic volumetric examinations of the RCP hold-down bolts at Byron and Braidwood and the pressurizer hold-down bolts at Braidwood.

(2) Periodic visual examinations that include parameters and criteria to detect a corrosive environment that supports SCC potential for all high-strength bolting greater than 1-in. nominal diameter will be included as Enhancement #5 to the ASME Section XI, Subsection IWF program. The visual examinations will include 100 percent of accessible high-strength bolting greater than 1-in. nominal diameter within the scope of the IWF program prior to the period of extended operation, and then every 10 years thereafter. These examinations will include parameters and criteria to identify if the bolting has been exposed to moisture or other contaminants by evidence of moisture, residue, foreign substance, or corrosion. Conditions identified during the periodic visual examinations that identify a potential corrosive environment that supports SCC will be entered in the CAP.

(3) Adverse conditions identified during the periodic visual examinations that are entered into the CAP will be evaluated by engineering to determine if the bolt has been exposed to a corrosive environment with the potential to cause SCC. The conditions will be subjected to supplemental visual examination or analysis of residue to determine if there is a potential for SCC. The identified bolts will be included in a sample population for each specific bolt material where SCC is a concern, then a sample of 20 percent (rounded up to the nearest whole number) of the bolts in the sample population, with a maximum sample size of 25 bolts, will be subject to supplemental volumetric examination to determine if SCC is present. The results of such volumetric examinations will be evaluated to determine if additional actions are warranted, and the CAP will be used to determine if any other corrective actions may be required per the CAP.

(4) Since all of the IWF program components utilizing high-strength bolting are located within the same confined area of the secondary shield wall, they share a common environment and have a low potential to be exposed to a corrosive environment due to the limited components contained in the area. In addition, other programs such as the Boric Acid Corrosion, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, Closed Treated Water Systems, and External Surfaces Monitoring of Mechanical Components AMPs, as well as leakage monitoring required by TSs, provide additional assurance that any changes to current environmental conditions will be identified and appropriate actions taken.

The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.S3 and finds it partially acceptable because there have been numerous volumetric examinations of bolting with the same material and similar or bounding environments and these examinations have not identified SCC. Also, 100 percent of susceptible ASME A540 high-strength bolting within the scope of the IWF program will be visually examined every IWF interval and followed up by volumetric examinations of a representative sample of bolts, if necessary. However, the staff did not find the response completely acceptable because:

- The applicant’s response to RAI B.2.1.31-3 states that the periodic visual examinations that will be performed will identify conditions that show evidence that a bolt has been exposed to a potentially corrosive environment and that an engineering evaluation will determine if the bolt has actually been exposed to a corrosive environment with the potential to cause SCC. The AMP does not address what factors will be considered in this evaluation in order to determine whether a "potential" corrosive environment identified in the visual examination is indeed a corrosive environment where supplemental volumetric examinations would be needed, particularly when no moisture is present.

- For the visual inspections proposed by the applicant, the program relies on indications related to the current or former presence of moisture. Given that these environmental impact indicators used to detect a corrosive environment could be removed over time (e.g., cleanup of water stains, painting of steel), it is not clear whether using visual inspections for the listed parameters at a 10-year interval will be able to ensure adequate aging management of high-strength SA 540 bolts greater than 1″ diameter.

The staff noticed that although the applicant's proposed approach to use periodic visual examinations to detect a corrosive environment for SCC potential in high-strength bolting applies to both A490 and SA 540 bolts, the staff's concerns related to visual examination to detect this aging effect are specific to the ASME SA 540 bolts. The staff's basis for restricting the requests to the SA 540 bolts is that the applicant does not plan to perform volumetric examinations on these bolts to identify cracking due to SCC. The applicant is crediting the numerous volumetric examinations of reactor head closure stud bolting with no evidence of SCC. Since there will be no volumetric examinations on the RCP hold-down bolts at BBS nor the pressurizer hold-down bolts at Braidwood, the staff needed additional information to assess whether the periodic visual examinations planned for IWF high-strength SA 540 bolts will be able to detect SCC.

By letter dated May 22, 2014, the staff issued RAI B.2.1.31-1b, requesting that the applicant:

(1) Describe the qualitative or quantitative acceptance criteria that will be used to (a) determine whether a corrosive environment exists or existed and (b) conclude that supplemental volumetric examinations will be performed.

(2) Clarify whether the acceptance criteria used for monitoring to detect this aging effect are the existence of environmental indicators that a corrosive environment exists or existed. If not, the staff requested that the applicant state the acceptance criteria to be used for monitoring. If so, given that the environmental indicators of a corrosive environment could be removed prior to visual inspections being conducted, the staff requested that the applicant provide information to support a conclusion that monitoring these parameters using visual inspection over a 10-year interval will be effective in managing this aging effect even if the environment indicators of a present or past corrosive environment are removed.

In its response dated June 16, 2014, the applicant stated that it will revise implementing procedures and AMP bases documents to include specific acceptance criteria to be used during visual examinations to determine whether a corrosive environment exists or existed. The applicant stated several parameters that will be used to address the qualitative and quantitative acceptance criteria. If moisture is detected at or near a bolt or stud, examples of parameters that will be considered are: the source of leakage or condensation, the proximity of the moisture, the chemical characteristics of the moisture, the potential pathway of the moisture, the material condition of the bolt or stud, including the presence and amount of any corrosion, and the material condition of any accessible concrete or grout near the bolt location. The applicant stated that it will also consider these factors if there is evidence that moisture had been present. The applicant also stated "the extent to which each of the…environmental indicators will be considered and weighed in the engineering evaluation will be determined by the conditions that are observed during the initial visual examinations of the bolting locations and during any followup visual examination or analysis."

In response to part 2 of RAI B.2.1.31-1b, the applicant provided further information to support its conclusion that monitoring the environmental indicators described above will be effective in managing aging of high-strength bolting in IWF applications. The applicant stated that its conclusion is based on the following:

- The bolting material is carbon steel, and if a corrosive environment exists that could potentially lead to SCC, the bolts would also exhibit surface corrosion, which would be detected through visual examinations
- All of the SA 540 bolts are located in the same confined area inside the secondary shield wall. There is a limited number of components contained in this area, and there are no systems containing raw water that could leak contaminants onto these bolts. Also, there are chemical control programs and procedures that limit the types of chemicals that can be brought into the area, limiting the potential for a chemical to be spilled onto the bolts and cause a corrosive environment
- Other plant programs and AMPs require that examinations be performed on components inside the secondary shield wall. Some examples are the Boric Acid Corrosion program, Closed Treated Water Systems Inspection program, ASME Section XI Inservice Inspection, and External Surfaces Monitoring. In addition, leakage monitoring is also required by Technical Specifications during reactor operation and start-up. If leakage or a corrosive environment is detected, the condition would be entered into the corrective action program and would lead to an evaluation for a corrosive environment and any potential effects on affected components

The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.S3 and finds it acceptable because the applicant has cited multiple appropriate factors that will be considered during visual examinations in conjunction with one another to determine whether a corrosive environment exists or existed. The applicant also demonstrated that it will be able to detect a corrosive environment with the potential to cause SCC prior to the occurrence of SCC in SA 540 bolts. In addition, the applicant will perform volumetric examinations of high strength SA 540 bolts if it is determined that the bolts have been exposed to an environment with the potential to cause SCC. The staff's concerns described in RAIs B.2.1.31-3 and B.2.1.31-1b are resolved.

Enhancement 1. LRA Section B.2.1.31 includes an enhancement to the "scope of program," "preventive actions," and "monitoring and trending" program elements. The applicant stated that it will add the MC supports for the transfer tube in the refueling cavity in the containment structure and refueling canal in the fuel handling building to the scope of program. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S3 and finds it acceptable because when it is implemented, the IWF program will include all components in the scope of license renewal that are applicable to the IWF AMP in accordance with 10 CFR 54.4.

Enhancement 2. LRA Section B.2.1.31 includes an enhancement to the "preventive actions" program element. The applicant stated that it will enhance the IWF program to provide guidance for proper specification of bolting material, lubricants, and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. In its response to RAI B.2.1.31-1, the applicant stated that it will provide guidance such that bolting material with actual measured yield strength of 150 ksi or greater will not be used in the plant without engineering approval, and that it will revise implementing documents to specify storage requirements for high strength bolts that include the RCSC specifications.

GALL Report AMP XI.S3 states that the use of MoS_2 as a lubricant is a potential contributor to SCC when applied to high strength bolting. During its onsite audit of program implementing documents, the staff noticed that MoS_2 was used as a lubricant on bolt faying surfaces for NSSS supports and not to the threads of bolts, but that there was no clear prohibition of the use of MoS_2 on high-strength structural bolting in the scope of the IWF program. The staff needed additional information to determine whether the program will be enhanced to specifically prohibit the use of MoS_2 on structural bolting. Therefore, by letter dated February 7, 2014, the staff issued RAI B.2.1.31-2, requesting that the applicant clarify whether the use of lubricants containing MoS_2 would be expressly prohibited in bolting procedures. The applicant responded, by letter dated March 4, 2014, and stated that Enhancement #2 is revised to clarify that the use of lubricants containing MoS_2 for structural bolting is prohibited.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S3 and finds it acceptable because when it is implemented it will be consistent with GALL Report recommendation that the use of MoS_2 lubricants be prohibited due to the increased susceptibility to SCC.

Enhancement 3. LRA Section B.2.1.31 includes an enhancement to the “monitoring and trending” program element. The applicant stated that the enhancement will provide procedural guidance, regarding the selection of supports to be inspected on subsequent inspections, when a support is repaired in accordance with the CAP. The enhanced guidance will ensure that the supports inspected on subsequent inspections are representative of the general population. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S3 and finds it acceptable because when it is implemented it will ensure that the IWF sample population to be inspected is representative of aging of the entire population of components in the scope of the IWF program.

Based on its audit and its review of the applicant’s responses to RAIs B.2.1.31-1, B.2.1.31-2, B.2.1.31-3, B.2.1.31-1a, and B.2.1.31-1b, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S3. The staff also reviewed the exceptions associated with the “preventive actions” and “detection of aging effects” program elements, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the “scope of program,” “preventive actions,” and “monitoring and trending” program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.31 summarizes OE related to the ASME Section XI, Subsection IWF Program. The LRA states that, at Byron Station, Unit 1, during implementation of examinations for the ASME Section XI, Subsection IWF program in March of 2008, it was discovered that the cold load setting of a variable spring support for feedwater piping in the main steam isolation valve (MSIV) room was 7 percent lower than the design value. The condition was entered into the CAP and an evaluation determined that the as-found value was acceptable based on piping design tolerances and guidelines, so no additional supports required examination per the IWL Code. The support was adjusted to be in accordance with the design value, and a VT-3 preservice examination was completed in accordance with IWF requirements.

The LRA states that at Braidwood Station, Unit 2, during implementation of the examinations for the ASME Section XI, Subsection IWF program in October of 2006, it was discovered that there was no load on a variable spring support for chemical and volume control piping that attaches to an RCP. The condition was entered into the CAP for evaluation, and a review determined that the condition had not resulted in exceeding the allowable pipe stresses or support loads and that the support should be adjusted to be in accordance with the design value. The support was adjusted and, per IWF requirements, the scope of the IWF examinations were expanded to include adjacent supports and supports similar to the support that was discovered to be supporting no load. A VT-3 preservice examination by a qualified inspector was completed for the repair activity in accordance with IWF requirements. During the next outage, successive examination of the support was performed per IWF and did not identify any recordable indications.

The LRA states that at Braidwood Station, Unit 2, during implementation of the examinations for the ASME Section XI, Subsection IWF program in August of 2009, it was discovered that a pipe clamp was loose on a support for feedwater pipe in the MSIV room. The condition was reported in the CAP. Corrective actions included adjusting the support and expanding the scope of the IWF examinations to include adjacent supports and supports similar to the support with the identified deficiency. An evaluation determined that the condition did not result in degradation to the structural integrity of the supported piping because the original load path still existed. In accordance with IWF, once the support was adjusted, a VT-3 preservice examination was completed. The examination of the expanded scope supports did not identify any recordable indications. Successive examination during the next outage did not identify any recordable indications.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S3 was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.31 provides the UFSAR supplement for the ASME Section XI, Subsection IWF program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to entering the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by letters dated March 4, 2014, and June 16, 2014, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's ASME Section XI, Subsection IWF 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 the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Masonry Walls

Summary of Technical Information in the Application. LRA Section B.2.1.33 describes the existing Masonry Walls Program as consistent, with enhancements, with GALL Report AMP XI.S5, "Masonry Walls." The LRA states that the Masonry Walls Program is an existing program, implemented as part of the Structures Monitoring Program, and is based on the guidance provided in IE 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 Masonry Wall Program is a condition monitoring program that provides for periodic visual inspections of masonry walls exposed to air-indoor (uncontrolled), air with borated water leakage, and air-outdoor environments, conducted at a frequency not to exceed 5 years. The program inspects for loss of material and cracking, and it will be enhanced to inspect for shrinkage or separation and for gaps between the supports and masonry walls that could impact the intended function of the walls. The LRA further states that unacceptable conditions are evaluated or corrected in accordance with the CAP. Masonry Walls that are considered fire barriers are also managed by the Fire Protection Program, which is evaluated in SER Section 3.0.3.2.10.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S5.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.33 includes an enhancement to the "scope of program" program element. The applicant stated that, prior to the period of extended operation, masonry walls in the Radwaste and Service Building Complex (Radwaste Building and Original Service Building), Turbine Building Complex, and Switchyard Structures (Relay House) will be added to the "scope of program." The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations to include all masonry walls, identified as performing an intended function in accordance with 10 CFR 54.4, within the scope of the Masonry Walls AMP.

Enhancement 2. LRA Section B.2.1.33 includes an enhancement to the "parameters monitored or inspected" and "acceptance criteria" program elements. The applicant stated that, prior to the period of extended operation, additional guidance will be provided for inspection of masonry walls for shrinkage, separation, and gaps between the supports and the masonry walls that could impact the intended function of the masonry walls. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, it will make the program consistent with the GALL Report recommended parameters monitored or inspected and acceptance criteria for shrinkage and/or separation and cracking of masonry walls.

Enhancement 3. LRA Section B.2.1.33 includes an enhancement to the "detection of aging effects" program element. The applicant stated that, prior to the period of extended operation, personnel performing inspections and evaluations will be required to meet the qualifications described in ACI 349.3R. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, it will ensure that personnel performing visual inspections of masonry walls meet the qualifications described in ACI 349.3R.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S5. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.33 summarizes OE related to the Masonry Walls Program. A summary of the OE is given below.

- In October 2011, inspections of three masonry walls inside the auxiliary building at Byron identified general corrosion on wall support plates and anchor bolts of two of the walls, and general corrosion on the base plate and anchor bolts for the block wall column support on the other wall. The conditions were entered into the CAP and evaluated for potential impact on the intended function of masonry wall supports. It was concluded that there was adequate margin in the calculations for material loss such that the design capacity of the supports was not impacted. The cause was attributed to condensation that periodically accumulates on the floor within the fan supply room, and corrective actions consisted of monitoring the conditions for any further degradation and creating a work request to clean and coat the affected components.
- In September 2009, inspections of four masonry walls inside the auxiliary building at Braidwood identified localized cracking in one wall near a minor shrinkage crack in the mortar joint at the top two courses, and minor shrinkage cracks and paint chipping in another area of the same wall around a duct penetration. No significant spalling, popouts, cracks or efflorescence, missing or loose support bolts and mortar joints were observed. All four walls were evaluated as being acceptable as is with no required corrective action.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S5 was evaluated.

UFSAR Supplement. LRA Section A.2.1.33 provides the UFSAR supplement for the Masonry Walls Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Masonry Walls Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.20 Structures Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.34 describes the existing Structures Monitoring Program as consistent, with enhancements, with GALL Report AMP XI.S6, "Structures Monitoring." The LRA states that the Structures Monitoring Program is a condition monitoring program that was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes elements of the Masonry Wall Program and therefore, incorporates the requirements of NRC IE Bulletin 80-11, "Masonry Wall Design," and the guidance in 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 program includes provisions for periodic testing and assessment of groundwater chemistry and inspection of accessible below-grade concrete structures. Further, the inspection frequency for the in-scope structures will not exceed 5 years, with provisions for more frequent inspections when conditions are observed that have a potential for impacting an intended function.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S6.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.34, revised by letter dated December 19, 2014, includes an enhancement to the "scope of program" program element. The applicant stated that the "scope of program" will include the following additional structures:

- radwaste and service building complex
    - radwaste building
    - original service building
- turbine building complex
- yard structures
    - transformer foundations
    - valve and line enclosures
- fire protection structures-features
    - transformer fire barrier walls
    - fuel oil storage tank berm
- containment structure features
    - containment access facility (CAF) hallway

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will make the "scope of program" consistent with the GALL Report recommendations for including all structures, structural components, and structural commodities within the scope of license renewal, that are not covered by other structural AMPs.

Enhancement 2. LRA Section B.2.1.34 includes an enhancement to the "scope of program" program element. The applicant stated that the "scope of program" will include the following additional components and commodities:

- blowout panels
- building features – doors and seals, bird screens, louvers, windows
- compressible joints and seals, gaskets and moisture barriers
- concrete curbs
- electrical cable trays, conduits and tube tracks
- hatches and plugs
- insulation including jacketing
- manholes, handholes and duct banks
- metal components, including metal decking for concrete slabs, miscellaneous steel, sump screens and trench covers, and scuppers around the SFP
- new fuel storage racks
- offgas stack and flue

- panels, racks, cabinets, and other enclosures
- penetration seals and sleeves
- pipe whip restraints, jet impingement shields, and spray shields
- pipe, electrical and equipment component support members
- sliding surfaces
- SFP gates
- sumps and liners

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will make the "scope of program" consistent with the GALL Report recommendations for including all structures, structural components, and structural commodities within the scope of license renewal, that are not covered by other structural AMPs.

Enhancement 3. LRA Section B.2.1.34 includes an enhancement to the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements. The applicant stated that groundwater chemistry will be monitored on a frequency not to exceed 5 years for pH, chlorides, and sulfates, and that results exceeding the threshold criteria will be evaluated to assess the impact, if any, on below-grade concrete. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will make the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements consistent with the GALL Report recommendations for periodically monitoring groundwater chemistry to assess its impact, if any, on below-grade structures.

Enhancement 4. LRA Section B.2.1.34 includes an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated that based on groundwater chemistry monitoring results, it will select and inspect every 5 years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the aging management of below-grade structures will be consistent with the recommendations in GALL Report AMP XI.S6 for plants with aggressive groundwater or soil.

Enhancement 5. LRA Section B.2.1.34 includes an enhancement to the "detection of aging effects" program element. The applicant stated that the program will require (a) the evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below-grade concrete, when excavated for any reason. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the inaccessible below-grade concrete structural elements will be evaluated consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 6. LRA Section B.2.1.34 includes an enhancement to the "preventive actions" program element. The applicant stated that guidance will be provided for proper specification of high-strength bolting material and lubricant to prevent or mitigate degradation and failure of structural bolting. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the recommendations for proper specification of bolting material, lubricants, and installation torque or tension will be consistent with guidance in NUREG-1339, EPRI NP-5769, EPRI NP-5067, and EPRI TR-104213 for ensuring bolting integrity.

Enhancement 7. LRA Section B.2.1.34 includes an enhancement to the "preventive actions" program element. The applicant stated that storage requirements for high-strength bolts will be revised to include recommendations of the RCSC Specification for Structural Joints Using High-Strength Bolts, Section 2.0. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the storage requirements for high-strength bolts will be in accordance with the recommendations of the RCSC Specification for Structural Joints Using High-Strength Bolts, consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 8. LRA Section B.2.1.34 includes an enhancement to the "acceptance criteria" program element. The applicant stated that clarification will be made that loose bolts and nuts and cracked high-strength bolts are not acceptable unless accepted by engineering evaluations. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the acceptance criteria for structural bolting will be consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 9. LRA Section B.2.1.34 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that the parameters monitored will include the potential for reduction in concrete anchor capacity due to local concrete degradation. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the potential reduction in concrete anchor capacity due to local concrete degradation will be a parameter monitored or inspected consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 10. LRA Section B.2.1.34 includes an enhancement to the "detection of aging effects" program element. The applicant stated that personnel performing inspections and evaluations will be required to meet the qualifications specified within ACI 349.3R with respect to knowledge of ISI of concrete and visual acuity requirements. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the qualifications of personnel performing inspections and evaluations will be as specified in ACI 349.3R, consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 11. LRA Section B.2.1.34 includes an enhancement to the "acceptance criteria" program element. The applicant stated that the acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R will be required. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will make the acceptance criteria for concrete structures consistent with the guidance of ACI 349.3R.

Enhancement 12. LRA Section B.2.1.34 includes an enhancement to the "detection of aging effects" and "acceptance criteria" program elements. The applicant stated that inspection of elastomeric components such as vibration isolation elements and structural seals for cracking, loss of material and hardening will be performed. Visual inspections of elastomeric components are to be supplemented by feel or manipulation to detect hardening. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the guidance for monitoring elastomeric components will be consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 13. LRA Section B.2.1.34 includes an enhancement to the "detection of aging effects" and "acceptance criteria" program elements. The applicant stated that accessible sliding surfaces will be monitored to detect loss of mechanical function or significant loss of material due to wear, corrosion, debris, dirt, distortion, or overload that could restrict or prevent sliding of surfaces as required by design. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, the guidance for monitoring accessible sliding surfaces will be consistent with the recommendations in GALL Report AMP XI.S6.

Enhancement 14. LRA Section B.2.1.34 includes an enhancement to the "detection of aging effects" program element. The applicant stated that its requirements for monitoring the leak detection sight glasses associated with the refuel cavity, transfer canal, SFP, and refueling water storage tank (RWST) on a periodic basis will be formalized. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will ensure that there is a method for monitoring leakage through the liners of the SFPs, fuel transfer canals, and refueling cavities.

Enhancement 15. LRA Section B.2.1.34 includes an enhancement to the "detection of aging effects" program element. The applicant stated that visual inspections of submerged concrete structural elements will be required by dewatering a structure or by a diver if the structure is not dewatered at least once every 5 years (Byron only). The staff noticed that this enhancement is applicable to the circulating water pump house and associated flume, and the natural draft cooling tower basins, which are structures that do not exist at Braidwood. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will provide a method to inspect submerged concrete structural elements.

Enhancement 16. LRA Section B.2.1.34, amended by letter dated April 17, 2014, in response to RAI B.2.1.34-1, includes and enhancement to the Structures Monitoring Program. The applicant stated that at each site, one-time sampling activities will be performed on below-grade, reinforced concrete at specific locations in the tendon tunnels. Locations exhibiting significant mineral deposits will be selected to serve as leading indicators for potential reinforced concrete degradation as a result of exposure to groundwater in-leakage and buildup of mineral deposits. Corrective actions, if necessary, will be taken prior to the period of extended operation.
One-time sampling activities will be performed as follows:

- Obtain water in-leakage samples, at representative locations with mineral deposits due to water in-leakage, and analyze for pH, chlorides, sulfates, minerals, and iron content.
- Obtain representative mineral deposit samples and analyze for chemical composition.
- Remove three concrete core samples.
    - Test two of the concrete core samples for compressive strength and perform petrographic examination of the core samples. Select representative locations for the concrete core samples that include one with significant mineral deposits and another at a location with no mineral deposits for comparative purposes.

- Drill an additional core at the crack with significant mineral deposits and subject the core to petrographic examination.

- Expose and examine reinforcing steel at two locations, with water in-leakage, cracks, and significant mineral deposits.
- Collectively evaluate the results from the water in-leakage analysis, the chemical composition of the mineral deposits, examination of the exposed reinforcing steel, and the core sample testing to confirm there is no significant degradation to the reinforced concrete material properties and to determine if additional corrective actions are necessary. Additional corrective actions may include, but are not limited to, an extent of condition review for other potentially impacted structures, more frequent examinations, and additional sampling and analysis, as appropriate.

The staff reviewed this enhancement and finds it acceptable because performance of these activities at each site, prior to the period of extended operation, would (1) confirm the source of the mineral deposits and (2) determine any impact of the water in-leakage on the reinforced concrete in the AFW, main steam, and tendon tunnels where the mineral deposits were observed. This enhancement, to address plant-specific OE, provides sufficient information to demonstrate that the effects of aging will be adequately managed by the Structures Monitoring Program.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S6. In addition, the staff reviewed the enhancements associated with the “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Enhancement 17. LRA Section B.2.1.34, as amended by letter dated June 16, 2014, in response to RAI 3.5.2.10-1, includes an enhancement to the Structures Monitoring Program. The applicant stated that, prior to the period of extended operation, the program will be enhanced to:

> [p]erform visual inspections of polymeric components, such as blowout panels, for changes in material properties. Observations of material discoloration, cracking, crazing, and loss of material will provide visual indications of changes in material properties prior to a loss of component intended function.

The staff reviewed this enhancement and finds it acceptable because the applicant has identified the parameters monitored or inspected for polymeric components, which are capable of being detected during the routine visual inspections, performed in accordance with the Structures Monitoring Program.

Operating Experience. LRA Section B.2.1.34 summarizes OE related to the Structures Monitoring AMP. A summary of the OE is given below.

- In June 2012, work activities at Byron required an excavation on the east side of the Turbine Building Heater Bay. During this time, a Structures Monitoring program engineer took the opportunity to perform and opportunistic inspection of the exposed, below-grade concrete. The groundwater environment at the heater bay foundation is considered to be similar to that of other areas across the site. Hammer soundings and examination of the concrete revealed no signs of degradation.

- In 2006, a Structures Monitoring engineer investigated the cause of water intrusion in the MSIV rooms. The engineer identified degradation of the sealant material used in the isolation joints between the MSIV rooms and the Units 1 and 2 containment buildings. The condition was entered into the CAP and evaluated for potential impact. The corrective actions taken included cleaning, inspecting and replacing the degraded sealant material as required to restore the isolation joints and prevent further degradation. Subsequent inspections verified the restoration of the isolation joints.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of an RAI, as discussed below.

During a walkdown of Byron and Braidwood's main steam and tendon tunnels, the staff observed white material deposits, or efflorescence, on some below-grade reinforced concrete walls. A review of OE revealed similar conditions in the AFW tunnel concrete walls. Through discussions with the applicant, the staff learned that the cracks through which the material may be leaching have existed since initial plant construction, and the material deposits are considered to be the result of the limestone backfill migrating though these cracks. The staff noticed that the groundwater at both BBS is considered aggressive due to high chlorides (i.e., >500 ppm) and is concerned that the observed material deposits could also be the result of material leaching from the concrete structures; therefore, by letter dated March 18, 2014, the staff issued RAI B.2.1.34-1 requesting that the applicant (1) state what actions, if any, have been taken to determine the composition of the material (white deposits) and state whether an evaluation has been performed to determine the source of the material deposits, and (2) considering that the groundwater is aggressive, state what actions, if any, have been taken to evaluate the condition of the concrete in these below-grade structures.

In its response dated April 17, 2014, with respect to part (1) of RAI B.2.1.34-1, the applicant stated that the mineral deposits have not been analyzed for chemical composition, but evaluations at Byron have concluded that the source has been attributed to the evaporation of water in-leakage that has passed through the backfill material. At Byron in 1996, an evaluation and investigation was conducted in portions of the AFW tunnels, main steam tunnels, and tendon tunnels that have experienced water in-leakage in inactive shrinkage cracks and constructions joints since initial construction. The water in-leakage was attributed to surface water runoff that collects and is contained in this area, which was backfilled with crushed dolomite, not limestone. In 1997, corrective action was taken to cover the ground surface with pavement, above the contained area, which reduced the amount of water in-leakage. Although the groundwater has been characterized as aggressive with respect to chlorides, a water sample taken in 2013 from the tendon tunnel at Byron was analyzed and determined to be nonaggressive. The applicant further stated that no specific evaluation or investigation as to the source of the mineral deposits has been conducted at Braidwood, and that the observed mineral deposits at Braidwood are much less than at Byron, most likely due to the sand backfill used at Braidwood, as opposed to the crushed dolomite material.

With respect to part (2) of RAI B.2.1.34-1, the applicant described actions taken to evaluate the condition of the concrete and enhanced the Structures Monitoring Program, described in Enhancement 16 above, to include confirmatory activities to ensure that the below-grade reinforced concrete in this area is in good condition. The applicant stated that:

> [a]lthough the groundwater has been characterized as aggressive, evaluation of the accessible below-grade concrete during routine and ongoing visual and hammer sounding examinations performed at Byron and Braidwood have not revealed any degradation of concrete due [to] leaching or chemical attack. As discussed above, the groundwater at Byron and Braidwood is not aggressive with respect to pH and sulfate values, therefore concrete degradation due to chemical attack or leaching is not expected to occur. The concrete is being monitored, managed, and maintained by the Structures Monitoring (B.2.1.34) aging management program. Concrete at crack locations has been determined to be structurally sound. Some shallow patches installed for cosmetic reasons, have degraded but the continuing concrete inspections have not detected any concrete degradation beyond the original superficial degradation that existed prior to the shallow patches. Any adverse conditions observed have been documented and reported in the corrective action program for evaluation and resolution. The evaluations have resulted in varying degrees of actions taken, such as no action needed, repair of an area to prevent additional or further degradation, additional examination for further evaluation, and more frequent monitoring. The evaluations have concluded there is no evidence of structural degradation (i.e., no significant cracking, deflection, weakened or softened concrete) of the concrete at these below-grade structures that would challenge or impact the integrity of the structures.

The applicant further stated that activities will be performed to confirm that the mineral deposits observed are not an indication of chemical attack or leaching and that the underlying concrete is in good condition. The staff's evaluation of the applicant's planned confirmation activities is documented in Enhancement 16 previously discussed.

The staff finds the applicant's response acceptable for the following reasons:

- The applicant has conducted an investigation and evaluation at Byron, which based on visual inspection did not identify conditions indicative of weakening or softening of the concrete. Therefore, the applicant concluded that the source of the material deposits is from the evaporation of water in-leakage that has passed through the backfill material. Corrective action was taken at Byron to reduce the amount of water in-leakage by placing a concrete slab above the location that collects and contains the surface water runoff or groundwater. Recently, in 2013, the applicant also took a water sample from the in-leakage in the tendon tunnel at Byron that determined the water was nonaggressive. Although no specific evaluation or investigation has been performed at Braidwood, the observed mineral deposits are much less than at Byron, and the applicant continues to monitor the conditions during routine Structures Monitoring inspections. Additionally, at both Byron and Braidwood, the applicant has committed to obtain representative mineral deposit samples to analyze for chemical composition prior to the period of extended operation, which will confirm the source of the material deposits.

- The applicant's evaluation of the accessible below-grade reinforced concrete during routine and ongoing visual and hammer sounding examinations, at both BBS, has not revealed any degradation of concrete due to leaching or chemical attack. The concrete at inactive crack locations has been determined to be structurally sound. The applicant has also taken the opportunity to inspect inaccessible below-grade areas of the concrete, exposed during an excavation at Byron, to assess the impact of aggressive groundwater on concrete structures, which is consistent with recommendations in GALL Report AMP XI.S6. Additionally, the applicant has committed to perform one-time sampling activities at each site to confirm that the concrete is in good condition.

The staff's concern described in RAI B.2.1.34-1 is resolved.

Based on its audit, its review of the application, and its review of the applicant's response to RAI B.2.1.34-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S6 was evaluated.

UFSAR Supplement. LRA Section A.2.1.34 provides the UFSAR supplement for the Structures Monitoring AMP. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to implement the enhancements to the program prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Structures Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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).

3.0.3.2.21 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B.2.1.35 describes the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as consistent, with enhancements, with GALL Report AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants." The LRA states that the scope of this AMP includes the river screen house and essential service water cooling towers at Byron and the essential service cooling pond and lake screen structures at Braidwood. The LRA also states that this is a condition monitoring program, based on guidance provided in NRC RG 1.127 and ACI 349.3R-02, and will be used to manage loss of material, loss of preload, cracking, loss of bond, loss of material (spalling, scaling) and cracking, increase in porosity and permeability, change in material properties, reduction in heat transfer, loss of strength, and loss of form. The LRA further states that the inspections of water-control structures are performed at intervals not to exceed 5 years.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S7.

The staff also reviewed the portions of "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.35 includes an enhancement to the "preventive actions" program element. The applicant stated that guidance for specification of structural bolting material and lubricant to prevent or mitigate degradation and failure of structural bolting will be provided. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "preventive actions" program element consistent with the GALL Report recommendations for selection, replacement, and installation of bolting material and lubricants.

Enhancement 2. LRA Section B.2.1.35 includes an enhancement to the "preventive actions" program element. The applicant stated that the storage requirements for structural bolting will be revised to include recommendations of the RCSC Specification for Structural Joints Using High-Strength Bolts. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "preventive actions" program element consistent with the GALL Report recommendations for storage, lubricants, and SCC potential of high-strength structural bolting.

Enhancement 3. LRA Section B.2.1.35 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that the potential for reduction in concrete anchor capacity due to local concrete degradation will be included. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, it will make the "parameters monitored or inspected" program element consistent with the GALL Report recommendations for monitoring aging effects associated with anchor bolts and the cracking of concrete around the anchor bolts.

Enhancement 4. LRA Section B.2.1.35 includes an enhancement to the "parameters monitored or inspected" and "acceptance criteria" program elements. The applicant stated that all aging effects addressed by ACI 349.3R will be included in procedures and that the acceptance and evaluation of structural concrete will be required using quantitative criteria based on Chapter 5 of ACI 349.3R. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "parameters monitored or inspected" program element consistent with the GALL Report recommendations for inspection of concrete structures, and the "acceptance criteria" program element consistent with the GALL Report recommendations for determining the adequacy of observed aging effects.

Enhancement 5. LRA Section B.2.1.35 includes an enhancement to the "parameters monitored or inspected" and "acceptance criteria" program elements. The applicant stated that clarification(s) will be made to specify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluation. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S7 and finds it acceptable because, when implemented, it will make the “parameters monitored or inspected” and “acceptance criteria” program elements consistent with the GALL Report recommendations for either accepting conditions by performing engineering evaluations or taking corrective actions.

Enhancement 6. LRA Section B.2.1.35 includes an enhancement to the “parameters monitored or inspected” program element. The applicant stated that steel components subject to RG 1.127 will be required to be inspected for loss of material. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the “parameters monitored or inspected” program element consistent with the GALL Report recommendations for the inspection of steel components for loss of material.

Enhancement 7. LRA Section B.2.1.35 includes an enhancement to the “detection of aging effects” program element. The applicant stated that inspectors will be required to work under the direction of a qualified engineer for submerged concrete inspections. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the “detection of aging effects” program element consistent with the GALL Report recommendations for inspections being conducted under the direction of qualified engineers experienced in the investigation, design, construction, and operation of these types of facilities.

Enhancement 8. LRA Section B.2.1.35 includes an enhancement to the “detection of aging effects” program element. The applicant stated that special inspections will be required to be performed in the event of large floods, hurricanes, and intense local rainfalls. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the “detection of aging effects” program element consistent with the GALL Report recommendations for special inspections immediately following the occurrence of significant natural phenomena.

Enhancement 9. LRA Section B.2.1.35 includes an enhancement to the “detection of aging effects” program element. The applicant stated that increased inspection frequency will be required if the extent of degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next regularly scheduled inspection. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the “detection of aging effects” program element consistent with the GALL Report recommendations for frequency of inspections.

Enhancement 10. LRA Section B.2.1.35 includes an enhancement to the “detection of aging effects” program element. The applicant stated that two actions will be required: (1) the evaluation of the acceptability of inaccessible areas, when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas; and (2) examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the “detection of aging effects” program element consistent with the GALL Report recommendations for the evaluation of aging effects in inaccessible and below-grade concrete areas.

Enhancement 11. LRA Section B.2.1.35 includes an enhancement to the "detection of aging effects" program element. The applicant stated that raw water and groundwater chemistry will be monitored at least once every 5 years for pH, chlorides, and sulfates and will be confirmed that the raw water and groundwater remains nonaggressive, or results exceeding criteria will be evaluated to assess impact, if any, on submerged concrete. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "detection of aging effects" program element consistent with the GALL Report recommendations for monitoring the raw water and groundwater chemistry at least once every 5 years.

Enhancement 12. LRA Section B.2.1.35 includes an enhancement to the "detection of aging effects" program element. The applicant stated that based on groundwater chemistry monitoring results, a structure that will be used as a leading indicator for the condition of below-grade concrete exposed to groundwater will be inspected every 5 years. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "detection of aging effects" program element consistent with the GALL Report recommendations for the inspection of inaccessible areas.

Enhancement 13. LRA Section B.2.1.35 includes an enhancement to the "detection of aging effects" program element. The applicant stated that visual inspections of submerged concrete structural components will be required by dewatering a structure or by a diver if the structure is not dewatered at least once every 5 years. The applicant also stated that maintenance procedures will be enhanced to require opportunistic inspection of submerged concrete structures when they are dewatered and made accessible. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "detection of aging effects" program element consistent with the GALL Report recommendations for the inspection of submerged concrete structures.

Enhancement 14. LRA Section B.2.1.35 includes an enhancement to the "monitoring and trending" program element. The applicant stated that degraded conditions will be required to be documented and trended until the condition is no longer occurring or until a corrective action is implemented. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will make the "monitoring and trending" program element consistent with the GALL Report recommendations for monitoring degraded conditions.

Enhancement 15. LRA Section B.2.1.35 includes an enhancement to the "parameters monitored or inspected" program element. The applicant stated that, for Byron, the parameters to be monitored and inspected at the essential service water cooling towers (SXCTs) will "include visual inspection for loss of material and reduction of heat transfer for the cooling tower fill, and visual inspection with physical manipulation for change in material properties associated with the polyvinyl chloride (PVC) drift eliminators and fiberglass support beams for the drift eliminators." The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will provide the appropriate parameters to be monitored or inspected for aging effects associated with the cooling tower fill, PVC drift eliminators, and associated fiberglass support beams.

Enhancement 16. LRA Section B.2.1.35 includes an enhancement to the "detection of aging effects" and "monitoring and trending" program elements. The applicant stated that the condition of the SXCTs at Byron will be managed as follows:

(a) Monitor and trend inspection activities at the SXCTs on an increased frequency, with inspections of the entire tower on a three (3)-year interval, and inspections of the fill support beams and air-inlet framing on a 1.5-year interval. The recommendations in Chapter 5 of ACI 349.3R will be used for quantitative acceptance and evaluation criteria.

(b) Develop a repair plan to address degradation of the SXCTs with specific emphasis and consideration for the fill support beams. Repairs that are required will be scheduled based on a ranking of the condition observed and the potential for the degradation to progress or propagate.

The staff reviewed the "Byron Generating Station – Inspection of Essential Service Water Cooling Tower Final Report," during its onsite audit, to determine if the program enhancement would adequately address the operating experience at the SXCTs. The staff noticed that the inspection was conducted by licensed professional engineers and confirmed that the inspection followed the guidance in ACI 349.3R, as described in the "operating experience" portion of LRA Section B.2.1.35. The staff noticed that the OE summary associated with the SXCTs at Byron adequately describes the inspection report findings and recommendations. The LRA states, "in summary, no conditions were identified that would challenge the near term structural capability of the SXCTs. Specific, localized degradation identified during the inspections that require repair were identified for corrective action."

The staff reviewed this enhancement for the SXCTs against the corresponding program elements in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will ensure that visual inspections, by qualified personnel using the quantitative evaluation criteria in accordance with ACI 349.3R, are performed more frequently than the five years recommended in the GALL Report, such that timely corrective action will be taken prior to a loss of intended function. The five year inspection interval recommended in the GALL Report has shown to be adequate to detect degradation of water-control structures. The staff notes that the three year inspection interval for the entire structure and the 1.5-year inspection interval for the fill support beams were determined based on a technical evaluation by the licensed professional engineers, following recommendations in ACI 349.3R. The staff agrees that the increased inspection frequencies, recommended by qualified personnel, are appropriate for monitoring and trending the condition of the SXCTs and managing the effects of aging. Additionally, Enhancement No. 9 to this program states that "if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection, increased inspection frequencies will be required." This provides reasonable assurance that appropriate corrective action is taken in a timely manner. The applicant's proposal to develop a repair plan, based on a ranking of the conditions detected, to ensure that appropriate actions are taken prior to a loss of intended function is consistent with the "corrective actions" program element. The staff's review of the "corrective actions" program element is documented in SER Section 3.0.4. This enhancement to the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, is consistent with the recommendations in the "detection of aging effects" and "monitoring and trending" program elements of GALL Report AMP XI.S7, and adequately addresses the plant-specific OE at Byron.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S7. In addition, the staff reviewed the enhancements associated with the “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.35 summarizes OE related to the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. A summary of the OE is given below.

- Initial inspections at Byron in the 1997–1998 timeframe as well as more recent followup inspections between the years of 2005 and 2010 identified concrete degradation including cracking, delamination, spalling of various degrees, and the presence of voids in the concrete fill support beams associated with the SXCTs. The degraded conditions were entered into the CAP and addressed individually as reported; however, a collective assessment has since been performed, and in 2012, a comprehensive inspection plan including followup and extent of condition was developed and implemented. An assessment was performed to evaluate the concrete quality and the cause of the noted degradation, investigate the presence of any additional voids in fill support beams, and evaluate the long-term durability of the concrete including any rebar degradation. In addition to visual inspections of both the interior and exterior of a “representative number of cells,” hammer soundings, exploratory openings to examine rebar, core bore samples, covermeter testing, and NDE were performed. Laboratory testing included petrographic examinations, depth of carbonation testing, chloride content testing, and compressive strength testing. Based on the findings of the applicant’s inspection report, specific localized degradation identified during the inspections that requires repair was identified for corrective action. Additional corrective actions, to address the global condition of the SXCTs, include, as stated in the LRA:
    - Provide additional guidance in inspection procedures for the SXCTs based on the finding included in the comprehensive inspection report.
    - Continue current monitoring and trending activities of the SXCTs. Increase the frequency of inspections of the entire tower to a 3-year interval and the fill support beams and air-inlet framing to a 1.5-year interval.
    - Develop a repair plan to address degradation of the SXCTs with specific emphasis and consideration for the fill support beams.
    - Develop and implement mitigation actions that will minimize thermal cycling and freeze-thaw conditions at the SXCTs to reduce or minimize any future degradation.
- In September 2011, the results of the Braidwood Cooling Lake Hydrographic Survey surveillance indicated a reduction in depth margin as compared to previously performed surveys. The historical data show that the depth margin of the ultimate heat sink (UHS) varied from survey to survey with no clear trend; therefore, the condition was entered into the CAP. The corrective actions taken were to first perform a visual inspection of the bottom of the UHS and determine the bottom condition with respect to the presence of silt, mud, and decaying vegetative growth, and second, remove the accumulated mud and silt from the UHS to restore margin. The third action was to evaluate inclusion of

the UHS parameter into the station's margin management database to ensure concerns related to the margin are understood, identified, evaluated, prioritized, and resolved to maintain and preserve design and operating margins to maintain nuclear safety.

The staff reviewed OE information in the application and during the audit to determine whether the applicant reviewed the applicable aging effects and industry and plant-specific OE. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

UFSAR Supplement. LRA Section A.2.1.35 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 noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed (Commitment No. 35, item 16) to implement the Byron essential service water cooling tower inspection and maintenance plan upon receipt of the renewed licenses, and will continue through the period of extended operation. The staff further noticed that the applicant committed (Commitment No. 35) to implement the remainder of the program enhancements prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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).

3.0.3.2.22 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. LRA Section B.2.1.36 describes the existing Protective Coating Monitoring and Maintenance Program as consistent, with enhancements, with GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance." The program is a condition monitoring program that provides for aging management of Service Level I coatings inside BBS containments in air with borated water leakage environments. The LRA states that the program includes a visual examination of all reasonably accessible Service Level I coatings inside containment during every refueling outage and includes assessment and repair for any condition that adversely affects the intended function of Service Level I coatings. The applicant stated that Service Level I coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components at BBS. However, the program ensures that Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling system (ECCS) suction strainers.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance."

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.36 includes an enhancement to the "detection of aging effects" program element. The applicant stated that it will add recurring work orders requiring Service Level I coating inspections every refueling outage. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because the GALL Report recommends conducting periodic inspections of all readily accessible coated surfaces each refueling outage or during other major maintenance outages, as needed. The staff finds that when this enhancement is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Enhancement 2. LRA Section B.2.1.36 includes an enhancement to the "detection of aging effects" program element. The applicant stated that coating inspectors will be required to be qualified to ASTM D 5498. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because the GALL Report recommends using ASTM D 5163, which states that the facility owner shall specify the requirements and guidelines for qualification and training of personnel involved in the coatings program. The staff reviewed ASTM D 5498 and finds it acceptable because it provides guidance on developing a program for the indoctrination and training of personnel performing coating and lining inspection work for nuclear facilities. The staff finds that when this enhancement is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Enhancement 3. LRA Section B.2.1.36 includes an enhancement to the "detection of aging effects" program element. The applicant stated that personnel will be required to be qualified to ASTM D 7108. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S8 and finds it acceptable because the GALL Report recommends using ASTM D 5163, which states that the facility owner shall specify the requirements and guidelines for qualification and training of personnel involved in the coatings program. The staff reviewed ASTM D 7108 and finds it acceptable because the standard provides guidance on developing a qualification program for a nuclear coating specialist. The staff finds that when this enhancement is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Enhancement 4. LRA Section B.2.1.36 includes an enhancement to the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that guidance for inspection and maintenance of coatings from RG 1.54 and requirements for coating condition assessment from ASTM D 5163-08 will be incorporated into the program. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because the GALL Report recommends using RG 1.54 and ASTM D 5163 for guidance on performing inspection and maintenance activities and for performing coating condition assessments. The staff finds that when this enhancement is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Enhancement 5. LRA Section B.2.1.36 includes an enhancement to the "detection of aging effects" program element. The applicant stated that the program will require thorough visual inspections of all coatings near sumps or screens associated with the ECCS by the coatings inspector(s). The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because the GALL Report recommends conducting thorough visual inspections near sumps or screens associated with the ECCS. The staff finds that when this enhancement is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Enhancement 6. LRA Section B.2.1.36 includes an enhancement to the "detection of aging effects" program element. The applicant stated that the program will specify instruments and equipment that may be needed for Service Level I coating inspections. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because the GALL Report recommends performing periodic inspections of Service Level I coatings. The staff finds that when this enhancement is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S8. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.36 summarizes OE related to the Protective Coating Monitoring and Maintenance Program. The LRA states that qualified inspectors perform Service Level I inspections inside containment at BBS every refueling outage. The LRA also states that based on review of recent Service Level I coating inspections and repair documentation it was determined that coating deficiencies identified in the containment buildings have not been significant and are usually limited to minor peeling, blistering, delamination, and minor surface rust.

The applicant provided the following OE:

Byron Station. In April 2008, during a Unit 1 refueling outage, the coatings coordinator performed an evaluation of the results of the Unit 1 containment coatings Service Level I inspection. The inspection included 100 percent of the accessible Service Level I coatings. The coatings coordinator concluded that there were no imminent coating concerns that would impede the safe operation, safe shutdown, or startup of the plant. The overall condition of the coating was determined to be good. However, several recommendations for repairs were made for future outages. A recommendation was made to repair and restore Service Level I coatings to several floor and wall areas, the electrical panel at the 'B' RCP, and the containment emergency hatch. To provide clarification on what constituted a "satisfactory" vs. an "unsatisfactory" inspection, the coatings coordinator was assigned an action tracking item to revise the inspection procedure acceptance criteria to provide clear definitions.

In August 2004, while reviewing a work order to apply Service Level I coating to several pipe supports, Byron maintenance personnel noticed that the supports were attached to pipes that contained fluid with temperatures in excess of 630 °F. The maintenance technician noticed that the engineering design change package, which specified the application of coating to the supports, did not specify a particular Service Level I coating to use for this application. Furthermore, it was reported that there were no Service Level I qualified coatings in stock approved for these relatively high temperature applications. The engineering staff identified a suitable coating for the application, one that was previously used at another station for a similar high-temperature application. The coating identified was Carbozinc 11 SG from Carboline. This coating was approved for use at Byron and the supports were subsequently coated with the high temperature rated coating.

Braidwood Station. In May 2012, the site coatings coordinator performed an evaluation of the results of the Unit 1 containment Service Level I coating inspections during a refueling outage. It was reported that the inspection was performed by a Level III qualified coating inspector in accordance with the coatings program implementing procedures. In addition, the inspection covered 100 percent of the accessible Service Level I coatings in the Unit 1 containment. As a result of the inspection, several deficiencies were identified including several instances of corrosion. The corrosion was evaluated and determined to be insignificant corrosion that would not impact the intended functions of the components and would be monitored, repaired as necessary, and trended by the coatings program in future outages. It was reported that recommendations for repairs included recoating the liner plate in several locations, coat areas of uncoated welds on Component Cooling lines that showed signs of rusting, coat uncoated piping field welds and pipe hangers associated with the Reactor Containment Fan Coolers plenums, clean and recoat surface rust on several structural steel members, hangers, piping, and valves where corrosion was identified by the inspector. The evaluation and recommendation were documented in the CAP and a work request was created to schedule the recommended repairs for a future outage.

In May 2007, Westinghouse issued a Technical Bulletin (TB-06-15, Revision 1) to communicate information regarding the design-basis accident (DBA) qualifications of two coating systems on equipment inside the Braidwood containment that was supplied by Westinghouse. It was stated that the historical documentation for Braidwood Station showed that these coatings were considered undocumented coatings and were included in the Braidwood quantity of unqualified coatings. In the Technical Bulletin, Westinghouse concluded that the coating systems may be considered DBA-acceptable coatings for use inside PWR containments. The Braidwood site engineering entered this item into the CAP for evaluation on the impact to the coating program. The evaluation determined that since the coatings in question are near the Reactor Coolant piping and would be in the zone of influence upon a Reactor Coolant pipe break, the coatings would still be assumed to fail even though they were qualified. As such, Braidwood site engineering did not increase the margin for loose debris in the ECCS suction strainers under DBAs.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.S8 was evaluated.

UFSAR Supplement. LRA Section A.2.1.36 provides the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program.

The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to ongoing implementation of the existing Protective Coating Monitoring and Maintenance Program for managing the effects of aging for applicable components during the period of extended operation. The staff also noticed that the applicant committed to implement the enhancements to the program prior to the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Protective Coating Monitoring and Maintenance Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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).

3.0.3.2.23 Metal Enclosed Bus

Summary of Technical Information in the Application. LRA Section B.2.1.40 describes the existing Metal Enclosed Bus Program as consistent, with enhancements, with GALL Report AMP XI.E4, "Metal Enclosed Bus." The LRA states that the Metal Enclosed Bus Program is an existing condition monitoring program that inspects the internal portions of metal-enclosed bus (MEB) for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The applicant also stated that bus insulation is visually inspected for signs of reduced insulation resistance such as embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate aging degradation. The applicant further stated that the bus internal insulating supports are visually inspected for structural integrity and signs of cracks. In addition, the applicant stated that external surfaces are visually inspected for loss of material due to general pitting and crevice corrosion. The applicant stated that enclosure assembly elastomers are visually inspected for surface cracking, crazing, scuffing, dimensional change, shrinkage, discoloration, hardening, and loss of strength. The applicant further stated that a sample of accessible bolted connections will be inspected for increased resistance of connection using resistance measurements. The LRA also states that the Metal Enclosed Bus Program including inspections and resistance measurements are performed at least once every 10 years with the existing program enhanced 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 compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.E4. In addition, the staff conducted walkdowns of in-scope MEB outside the auxiliary building. The staff also conducted an independent search of the applicant's OE database using keywords: "metal enclosed bus," "loose connections," and "water intrusion." The staff reviewed the Metal Enclosed Bus Program elements 1 through 6 based on the contents of the existing program as modified by the proposed enhancements. The staff interviewed the applicant's staff and reviewed onsite documentation provided by the applicant.

The staff noticed that age-related degradation of the MEB external structural supports will be managed under the applicant's "structures monitoring program." Using the applicant's structural monitoring program to inspect the MEB external structural supports is consistent with GALL AMP XI.E4 guidance. The staff also noticed that aging management of elastomers and MEB external surfaces will be implemented under the applicant's Metal Enclosed Bus Program instead of the applicant's "internal surfaces in miscellaneous piping and ducting components" program or "structures monitoring" program. Incorporating elastomer and external surfaces aging management into the Metal Enclosed Bus Program is an alternative consistent with GALL AMP XI.E4, "scope of program" program element guidance.

During the staff's review of implementation document MA-BY-725-515, "Preventive Maintenance of Non-Segregated Bus Duct," Revision 9, the staff noticed that in Section 4.4.8.2, the applicant required a torque check for bus insulation bolts. A torque check is not recommended per industry guidance. EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," Section 8.2 states, "inspect bolted joints for evidence of overheating, signs of burning or discoloration, and indication of loose bolts. The bolts should not be retorqued unless the joint requires service or the bolts are clearly loose. Verifying the torque is not recommended." The option for checking tightness of the bus insulator bolts is not in alignment with the EPRI guidance. In response to the staff concern, the applicant created AR 01552489 to reconcile the discrepancy.

The staff also reviewed the portions of the "detection of aging effects" and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.40 states an enhancement to the "detection of aging effects" program element. The applicant stated that the Metal Enclosed Bus Program would be enhanced to specify that a sample size of 20 percent of the accessible bolted connection population with a maximum sample size of 25 are to be inspected for increased resistance of connection by measuring the connection resistance using a micro-ohmmeter. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E4 and finds it acceptable because, when implemented, the applicant's basis document BBS-PBD-AMP-XI.E4, "Metal Enclosed Bus" AMP will be consistent with GALL AMP XI.E4 "detection of aging effects" program element. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E4 and finds it acceptable because, when implemented, the applicant's basis document BBS-PBD-AMP-XI.E4, "Metal Enclosed Bus" AMP will be consistent with GALL Report AMP XI.E4 "detection of aging effects" program element.

Enhancement 2. LRA Section B.2.1.40 includes an enhancement to the "acceptance criteria" program element. The applicant stated that the Metal Enclosed Bus Program would be enhanced to specify that the external surfaces of MEB enclosure assemblies are to be inspected for loss of material due to general, pitting, and crevice corrosion. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E4 and finds it acceptable because, when implemented, the applicant's basis document BBS-PBD-AMP-XI.E4, "Metal Enclosed Bus" AMP it will be consistent with the "acceptance criteria" program element of GALL AMP XI.E4.

Enhancement 3. LRA Section B.2.1.40 includes an enhancement to the "acceptance criteria" program element. The applicant stated that the Metal Enclosed Bus Program would be enhanced to specify the maximum allowed bus connection resistance values. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E4 and finds it acceptable because, when implemented, the applicant's basis document BBS-PBD-AMP-XI.E4 Metal Enclosed Bus AMP will be consistent with the "acceptance criteria" program element of GALL AMP XI.E4.

Based on its audit, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E4. In addition, the staff reviewed the enhancements associated with the "detection of aging effects" and "acceptance criteria" program elements and finds that, when implemented, they will make the applicant's AMP adequate to manage the applicable aging effects

<u>Operating Experience</u>. LRA Section B.2.1.40 summarizes OE related to the Metal Enclosed Bus AMP.

Examples of MEB OE provided in the LRA include:

- In May 1996, the Byron Unit 1 System Auxiliary Transformer (SAT) 142-2 4-kV nonsegregated MEB had a phase to ground fault. Byron Unit 1 was in Mode 5 for an outage. Byron Unit 2 was manually tripped due to the loss of Non-Essential Service Water and Station Air Compressors powered from the Unit 1 SAT. The event was entered into the corrective action program. The root cause determined that the phase to ground fault was due to a failed insulator. The insulator failure was caused by chronic water intrusion, that is, free water dripping on the insulator. The chronic water intrusion caused the eventual degradation of the insulator. The source of the water was rain water leaking through the insulator mounting bolt hole. The bolt hole was not properly sealed because a weld seam on the top of the duct prevented the insulator mounting head gaskets from sealing properly. A contributing cause was that the caulk in this region was not regularly examined as part of the periodic MEB inspections.

  Corrective actions included adding an explicit examination of the caulk to the MEB inspection surveillances, stressing the significance of the caulked joint to the MEB inspectors. There has been no indication of free water intrusion into the MEBs since these procedures were implemented at Byron.

- In March 2008, the Byron Unit 2 system auxiliary transformer (SAT) 242-2 4-kV nonsegregated MEB had a phase to ground fault. This resulted in an isolation of both Unit 2 SATs and thus a Loss of Offsite Power to Byron Unit 2. Unit 2 remained on-line throughout this event. The event was entered into the corrective action program. The root cause investigation determined that the phase to ground fault was due to a failed insulator. The insulator failure was due to age-related degradation of the insulator material. The degradation of the insulator material resulted in internal corona discharges, which is internal arcing across the insulators two metal bases. There was no indication of free water intrusion. The failed insulator was replaced in kind with a new insulator. The remaining insulators in the affected MEBs were high potential tested with satisfactory results. In order to prevent reoccurrence, high potential testing was incorporated into post-maintenance testing procedures for all MEBs. In addition, the MEB inspection procedures were strengthened to include an inspection of the boot seals, provide direction on the application of caulking, and provide direction on the application of the weather stripping on the removable cover. There have been no similar insulator failures experienced at Byron Station since the initial event in March 2008. No issues have been noted relating to the condition of the installed insulators.

The staff also reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff did not identify any OE that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP XI.E4 was evaluated.

<u>UFSAR Supplement</u>. LRA Section A.2.1.40 provides the UFSAR supplement for the Metal Enclosed Bus Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed (Commitment No. 40) to ongoing implementation and enhancement of the existing Metal Enclosed Bus Program for managing the effects of aging for applicable components during the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's Metal Enclosed Bus Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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).

3.0.3.2.24 Fatigue Monitoring

Summary of Technical Information in the Application. LRA Section B.3.1.1 describes the existing Fatigue Monitoring Program as consistent, with enhancements, with GALL Report AMP X.M1, "Fatigue Monitoring." The LRA states that the program manages cumulative fatigue damage by ensuring that the CUF remains within the design limit through the period of extended operation. The LRA states that this is accomplished by monitoring and tracking the critical thermal and pressure transients and verifying that the severity of actual operational transient parameters are bounded by the applicable design transient definitions. The LRA further states that the program will be enhanced to perform EAF analyses for critical RCS locations to evaluate the cumulative fatigue damage effect of the reactor coolant environment. The LRA also states that the program will be enhanced to evaluate the effects of the reactor coolant environment on RVI components with existing fatigue analyses.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP X.M1. For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

LRA Section B.3.1.1 states that the Fatigue Monitoring Program monitors and tracks critical thermal and pressure transients to ensure each analyzed component does not exceed the allowable cycle limits to ensure the fatigue analyses remain valid. The staff noticed that GALL Report recommends that the Fatigue Monitoring Program be credited to monitor and track transients assumed in fatigue usage analyses. However, the LRA also credits the Fatigue Monitoring Program to monitor and track transient cycles to ensure the validity of other fatigue analyses, such as flaw evaluations and crack growth rate analyses. The staff is unclear if these analyses are within the scope of the applicant's Fatigue Monitoring Program. By letter dated December 12, 2013, the staff issued RAI B.3.1.1-2, requesting that the applicant clarify if non-ASME Code Section III fatigue analyses are within the scope of the Fatigue Monitoring Program and to identify those analyses. The staff also requested the applicant to justify why it is appropriate to credit the Fatigue Monitoring Program to disposition those analyses in accordance with 10 CFR 54.21(c)(1)(iii) such that the effects of aging on the intended functions of applicable components will be managed through the period of extended operation.

By letter dated January 13, 2014, the applicant responded to RAI B.3.1.1.-2. The applicant stated that the scope of the Fatigue Monitoring Program includes analyses other than ASME Code Section III fatigue analyses. The applicant clarified that the program is credited for ensuring the transient inputs are not exceeded for ASME Code Section III fatigue exemptions, the allowable stress analyses associated with ASME Code Section III and ANSI B31.1, and the flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600. The applicant further stated that the transient inputs for these analyses are incorporated in LRA Tables 4.3.1-1 through 4.3.1-6, which include all of the transients that will be monitored and tracked by the enhanced Fatigue Monitoring program, which will ensure the associated aging effects on the intended functions of applicable components will be adequately managed for the period of extended operation. As a result of the response, the applicant added an additional enhancement, Enhancement 4, to the Fatigue Monitoring Program to increase the "scope of program" to include analyses other than ASME Code Section III fatigue analyses, stated as the following: "Increase the scope of the program to include transients used in the analyses for ASME Code Section III fatigue exemptions, the allowable stress analyses associated with ASME Code Section III and ANSI B31.1, and the flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600." The applicant also updated LRA Sections A.3.1.1, B.3.1.1, and A.5 to reflect this additional enhancement. The staff finds the applicant's response to RAI B.3.1.1-2 acceptable because the applicant expanded the scope of the Fatigue Monitoring Program to include non-ASME Code Section III fatigue analyses and confirmed that the transient inputs to these analyses will be monitored and tracked to ensure the validity of the analyses, which is consistent with GALL Report AMP X.M1. The staff's concern in RAI B.3.1.1-2 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "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, including Enhancement 4 that was added as a result of the applicant's response to RAI B.3.1.1-2.

Enhancement 1. LRA Section B.3.1.1 states an enhancement to the "scope of program," "preventive actions," "parameters monitored or affected," "acceptance criteria," and "corrective actions" program elements. The applicant stated that cumulative fatigue damage effects of the reactor coolant environment on component life will be evaluated for critical components for the plant identified in NUREG/CR-6260. Additional plant-specific component locations in the RCPB will be evaluated if they are more limiting than those considered in NUREG/CR-6260.

The "scope of program" program element of the GALL Report AMP X.M1 states for purposes of monitoring and tracking, the applicant should include, for a set of sample RCS components, fatigue usage calculations that consider the effects of the reactor water environment. This sample set is to include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the RCPB if they may be more limiting than those considered in NUREG/CR-6260. Consistent with the recommendations of GALL Report AMP X.M1, the applicant proposed to enhance its program to address EAF for the NUREG/CR-6260 sample locations and plant-specific bounding RCPB locations. The staff's review of the applicant's evaluation of the NUREG/CR-6260 sample EAF locations for a newer vintage Westinghouse plant and the methodology to identify plant-specific bounding EAF locations is documented in SER Section 4.3.4.2.

The "preventive actions" program element of the GALL Report AMP X.M1 states that program prevents the fatigue analyses from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. By managing those transients in the design fatigue analyses and environmental fatigue calculations, the applicant prevents the calculated environmentally adjusted cumulative usage factor (CUF_{en}) values from becoming invalid, which the staff finds consistent with the "preventive actions" program element.

The "parameters monitored or inspected" program element of the GALL Report AMP X.M1 states that the program monitors all plant design transients that cause cyclic strains and their number of occurrences. Alternatively, more detailed monitoring of local pressure and thermal conditions may be performed to allow the actual fatigue usage for the specified critical locations to be calculated. The staff noticed that the program, when enhanced, will address the cumulative fatigue damage effects of the reactor coolant environment on the critical components for the plant identified in NUREG/CR-6260 and additional plant-specific locations evaluated as more limiting. Consistent with the "parameters/monitored/inspected" program element, the program will provide a more detailed monitoring of components that contact the reactor coolant by evaluating the impact of the reactor coolant environment. The staff's review of the applicant's evaluation of the cumulative fatigue damage effects of the reactor coolant environment is documented in SER Section 4.3.4.2.

The "acceptance criteria" program element of the GALL Report AMP X.M1 states that the acceptance criterion is maintaining the cumulative fatigue usage below the design limit through the period of extended operation, with consideration of the reactor water environmental fatigue effects. The staff noticed that the program, when enhanced, would limit the number of cycles identified in the design fatigue analyses that included the effects of the reactor water environment. Thus, the program would ensure the Code design limit of 1.0 is not exceeded, consistent with the "acceptance criteria" program element.

The "corrective actions" program element of the GALL Report AMP X.M1 states that the program scope expansion includes consideration of other locations with the highest expected CUFs when considering environmental effects. Consistent with the "corrective actions" program element, the staff noticed that the program, when enhanced, would evaluate additional plant-specific component locations in the RCPB if they are more limiting than those considered in NUREG/CR-6260. The staff's review of the applicant's evaluation of the NUREG/CR-6260 sample locations for a newer vintage Westinghouse plant and the methodology to identify plant-specific bounding locations is documented in SER Section 4.3.4.2.

As a result of its responses to RAI 4.3.9-1, RAI 4.6.5-1, and RAI 4.6.6-1, by letter dated May 23, 2014, the applicant amended LRA Section B.3.1.1 to provide additional details about the transients and components within the scope of the Fatigue Monitoring Program, which the staff finds acceptable. The staff's evaluations of RAI 4.3.9-1, RAI 4.6.5-1, and RAI 4.6.6-1 are documented in SER Sections 4.3.9, 4.6.5, and 4.6.6, respectively.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because, when the program is implemented in accordance with the enhancement, the program will have addressed the criteria for monitoring EAF component locations in GALL AMP X.M1 and therefore be consistent with the "scope of program," "preventive actions," "parameters monitored," "acceptance criteria," and "corrective actions" program elements criteria in GALL Report AMP X.M1.

Enhancement 2. LRA Section B.3.1.1 states an enhancement to the "scope of program," "preventive actions," "parameters monitored or affected," "acceptance criteria," and "corrective actions" program elements. The applicant stated that additional plant transients that are significant contributors to component fatigue usage will be monitored and tracked.

For the additional plant transients that will be monitored as a result of this enhancement, it is unclear to the staff how the applicant's review process would ensure that the accumulated transients from initial plant startup will be appropriately accounted for, both in number of cycles and severity, prior to the program enhancement. By letter dated December 12, 2013, the staff issued RAI B.3.1.1-1 requesting that the applicant describe the methodology that will be used to identify additional plant transients that contribute significantly to the fatigue usage factor and explain how cycles from initial plant startup of these additional transients will be appropriately captured, both in cycle counts and severity, by the Fatigue Monitoring Program prior to entering the period of extended operation.

By letter dated January 13, 2014, the applicant responded to RAI B.3.1.1-1. The applicant stated that the methodology used to identify the additional plant transients that contribute significantly to the fatigue usage factor involved a comprehensive review of design specifications and design fatigue analyses. The applicant stated that the additional transients were discovered during operation of the plant from licensing basis evaluations subsequent to the original individual equipment or design specifications. The applicant provided examples of the subsequent licensing basis evaluations, such as the feedwater stratification transients. The applicant identified the additional transients to be monitored by the Fatigue Monitoring Program, which the staff confirmed are captured in transient tables in LRA Section 4.3.1. The applicant stated that these additional transients are: (1) pressurizer spray transients associated with plant heatups and cooldowns, (2) bypass line tempering valve failure, (3) excessive bypass feedwater flow, (4) RPV stud tensioning and detensioning, (5) RCP piping – loss of seal injection flow, and (6) RCP piping – loss of component cooling water flow. The applicant further stated that the transients contained in LRA Tables 4.3.1-1 through 4.3.1-6, which include the additional transients, have been baselined as of March 31, 2012. The applicant stated that transient cycles for the additional transients were determined using information retrieved from plant historical records and analysis of high resolution plant computer data. The applicant further stated that the enhanced program will monitor and track the additional transients through the period of extended operation. The staff finds the applicant's response acceptable because: (a) the applicant identified the plant transients that were not considered in the original analyses and significantly contribute to the fatigue usage factor, (b) the applicant will monitor and track those transients using the enhanced Fatigue Monitoring program to ensure that Code design limit is not exceeded, and (c) this demonstrated the program, as enhanced in accordance with enhancement No. 2, will be consistent with the GALL Report AMP X.M1. The staff's concern in RAI B.3.1.1-1 is resolved.

The "scope of program" program element of the GALL Report AMP X.M1 states that the scope includes those components that have been identified to have a fatigue TLAA and that the program monitors and tracks the number of critical thermal and pressure transients for the selected components. The staff noticed that, when enhanced, the applicant's program will monitor components that have been identified to have a fatigue TLAA and track all plant transients that are significant contributors to component fatigue usage, which is consistent with the "scope of program" program element.

The "preventive actions" program element of the GALL Report AMP X.M1 states that the program prevents the fatigue analyses from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. The staff noticed that, when enhanced, the program will prevent the calculated CUF values from becoming invalid by managing those transients assumed in the original design fatigue analyses and the additional transients discovered during subsequent licensing basis evaluations during operation of the plant, which is consistent with the "preventive actions" program element.

The "parameters monitored/inspected" program element of the GALL Report AMP X.M1 states that the program monitors all plant design transients that cause cyclic strains and which are significant contributors to the fatigue usage factor. The staff noticed that, when enhanced, the program will monitor and track the transients assumed in the original design fatigue analyses and the additional transients discovered during subsequent licensing basis evaluations during operation of the plant that significantly contribute to the fatigue usage factor, which is consistent with the "parameters monitored/inspected" program element.

The "acceptance criteria" program element of the GALL Report AMP X.M1 states that the acceptance criterion is maintaining the cumulative fatigue usage below the design limit through the period of extended operation. The staff noticed that the program, when enhanced, would limit the number of cycles of transients in the design fatigue analyses that significantly contribute to the fatigue usage factor. Thus, the program would ensure the Code design limit of 1.0 is not exceeded, consistent with the "acceptance criteria" program element.

The "corrective actions" program element of the GALL Report AMP X.M1 states that the program provides for corrective action to prevent the usage factor from exceeding the design code limit during the period of extended operation. The staff noticed that the program, when enhanced, would monitor and track the plant design transients that significantly contribute to the fatigue usage factor for all of the components that have been identified to have a fatigue TLAA to prevent the usage factor from exceeding the Code design limit of 1.0, which is consistent with the "corrective actions" program element.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because, when the program is implemented in accordance with the enhancement, the program will have addressed the transient monitoring criteria in GALL Report AMP X.M1 and therefore be consistent with the "scope of program," "preventive actions," "parameters monitored," "acceptance criteria," and "corrective actions" program elements criteria in GALL Report AMP X.M1.

Enhancement 3. LRA Section B.3.1.1 states an enhancement to the "scope of program," "preventive actions," "parameters monitored/affected," "acceptance criteria," and "corrective actions" program elements. The applicant stated that RVI components will be evaluated for the effects of the RCS water environment using existing fatigue CUF analyses to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121.

LRA Section 4.3.5 provides the applicant's TLAA for RVI components with fatigue usage calculations. The applicant dispositioned the TLAA in accordance with 10 CFR Part 54.21(c)(1)(iii) such that the Fatigue Monitoring program will manage the effects of aging due to fatigue on the intended functions of the RVI components. However, the applicant did not provide enough information on the specific approach or method by which the Fatigue Monitoring program will evaluate the RVI components with existing fatigue CUF analyses to address the effects of the RCS water environment. By letter dated December 12, 2013, the staff issued RAI B.2.1.7-4 requesting that the applicant indicate the RVI components with existing CUF analyses for which the Fatigue Monitoring Program will evaluate the effects of RCS water environment and provide the associated material type and CUF value for each component. In addition, the applicant was requested to describe and justify the approach and method that will be used to address the effects of RCS water environment on the RVI components with existing fatigue CUF analyses.

By letter dated January 13, 2014, the applicant responded to RAI B.2.1.7-4. The applicant stated that RVI components with existing CUF analyses for which the Fatigue Monitoring program will evaluate the effects of the RCS water environment are the upper core plate, upper core plate alignment pins, upper support plate, baffle plate, core barrel nozzle, lower radial restraints, lower core plate, and lower support columns. The applicant stated that each of the RVI components with existing CUF analyses will be evaluated by applying the environmental fatigue multipliers determined in accordance with the methodologies in NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," for austenitic SS components or NUREG/CR-6909, "Effects of LWR Coolant Environments on the Fatigue Life of Reactor Materials," for nickel alloy components. The applicant further stated that this approach and method is described in LRA Section 4.3.4. The staff finds this response acceptable because the RVI components with existing fatigue analyses will be evaluated by the Fatigue Monitoring Program for the effects of the RCS water environment and because the applicant used a methodology to evaluate the environmental effects of fatigue that is consistent with the GALL Report. The staff's concern in RAI B.2.1.7-4 is resolved. The staff's review of the applicant's evaluation of assessing the impact of the reactor coolant environment is documented in SER Section 4.3.4.2. The staff's review of the applicant's RVIs fatigue analyses is documented in SER Section 4.3.5.2.

The "scope of program" program element of GALL Report AMP X.M1 states that for purposes of monitoring and tracking, the applicant should include, for a set of sample RCS components, fatigue usage calculations that consider the effects of the reactor water environment. The GALL Report states that this sample set is to include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the RCPB if they may be more limiting than those considered in NUREG/CR-6260. The staff noticed that, consistent with the recommendations of GALL Report AMP X.M1, the applicant's enhanced program will address EAF for the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and plant-specific bounding EAF locations. The staff's review of the applicant's evaluation of the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and the methodology to identify plant-specific bounding EAF locations is documented in SER Section 4.3.4.2.

The "preventive actions" program element of GALL Report AMP X.M1 states that the program prevents the fatigue analyses from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. The staff noticed that, by managing those transients assumed in the design fatigue analyses and environmental fatigue calculations, the applicant prevents the calculated CUF_{en} values from becoming invalid, which the staff finds consistent with the "preventive actions" program element.

The "parameters monitored or inspected" program element of the GALL Report AMP X.M1 states that the program monitors all plant design transients that cause cyclic strains and their number of occurrences. The GALL states that, as an alternative, more detailed monitoring of local pressure and thermal conditions may be performed to allow the actual fatigue usage for the specified critical locations to be calculated. The staff noticed that the program, when enhanced, will address the effects of the reactor coolant environment on the RVI components. The staff noticed that, consistent with the "parameters monitored or inspected" program element, the program will provide a more detailed monitoring of the RVI components by evaluating the cumulative fatigue damage effects of the reactor coolant environment.

The "acceptance criteria" program element of GALL Report AMP X.M1 states the acceptance criterion is maintaining the cumulative fatigue usage below the design limit through the period of extended operation, with consideration of the reactor water environmental fatigue effects described in the program description and scope of program. The staff noticed that the program, when enhanced, would limit the number of cycles identified in the design fatigue analyses that included the effects of reactor water environment, and therefore, the program would ensure the Code design limit of 1.0 is not exceeded, consistent with the "acceptance criteria" program element. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because when it is implemented, the applicant's program will be consistent with the recommendations of the GALL Report, as described above.

The “corrective actions” program element of the GALL Report AMP X.M1 states that the program scope expansion includes consideration of other locations with the highest expected CUFs when considering environmental effects. Consistent with the “corrective actions” program element, the staff noticed that the program, when enhanced, would evaluate additional plant-specific component locations in the RCPB if they are more limiting than those considered in NUREG/CR-6260. The staff’s review of the applicant’s evaluation of the NUREG/CR-6260 sample locations for a newer vintage Westinghouse plant and the methodology to identify plant-specific bounding locations is documented in SER Section 4.3.4.2.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because, when the program is implemented in accordance with the enhancement, the program will have addressed the criteria for monitoring transient cycles against applicable EAF fatigue calculations in GALL Report AMP X.M1 and will therefore be consistent with the “scope of program,” “preventive actions,” “parameters monitored,” “acceptance criteria,” and “corrective actions” program elements criteria in GALL Report AMP X.M1.

Enhancement 4. LRA Section B.3.1.1 states an enhancement to the “scope of program,” “preventive actions,” “parameters monitored or affected,” “acceptance criteria,” and “corrective actions” program elements. The applicant stated that the “scope of program” will be increased to include transients used in the analyses for ASME Code Section III fatigue exemptions, the allowable stress analyses associated with ASME Code Section III and ANSI B31.1, and the flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600.

The “scope of program” program element of the GALL Report AMP X.M1 states that the scope includes those components that have been identified to have a fatigue TLAA and that the program monitors and tracks the number of critical thermal and pressure transients for the selected components. The staff noticed that, when enhanced, the Fatigue Monitoring Program will include components with ASME Code Section III fatigue analyses, ASME Code Section III fatigue exemptions, allowable stress analyses associated with ASME Code Section III and ANSI B31.1, and flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600 and will monitor and track the transient inputs to these analyses, which is consistent with the “scope of program” program element.

The “preventive actions” program element of the GALL Report AMP X.M1 states that the program prevents the fatigue analyses from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. The staff noticed that, when enhanced, the program will prevent the calculated CUF values from becoming invalid by managing those transients assumed in the ASME Code Section III fatigue analyses and the analyses described in the enhancement, which is consistent with the “preventive actions” program element.

The “parameters monitored or inspected” program element of the GALL Report AMP X.M1 states that the program monitors all plant design transients that cause cyclic strains and which are significant contributors to the fatigue usage factor. The staff noticed that, when enhanced, the program will monitor and track the transients that significantly contribute to the fatigue usage factor and are assumed in the ASME Code Section III fatigue analyses and the analyses described in the enhancement, which is consistent with the “preventive actions” program element.

The “acceptance criteria” program element of the GALL Report AMP X.M1 states that the acceptance criterion is maintaining the cumulative fatigue usage below the design limit through the period of extended operation. The staff noticed that the program, when enhanced, would limit the number of cycles of transients that significantly contribute to the fatigue usage factor in the ASME Code Section III fatigue analyses and the analyses described in the enhancement. Thus, the program would ensure the Code design limit of 1.0 is not exceeded, consistent with the “acceptance criteria” program element.

The “corrective actions” program element of the GALL Report AMP X.M1 states that the program provides for corrective action to prevent the usage factor from exceeding the design code limit during the period of extended operation. The staff noticed that the program, when enhanced, would monitor and track the plant design transients that significantly contribute to the fatigue usage factor for all of the components that have been identified to have a fatigue TLAA, including the analyses described in the enhancement, to prevent the usage factor from exceeding the Code design limit of 1.0, which is consistent with the “corrective actions” program element.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because, when the program is implemented in accordance with the enhancement, the program will have defined how it will be implemented in comparison to other cycle-based analyses not defined in GALL Report AMP X.M1, and therefore the program meets the intent of the “scope of program,” “preventive actions,” “parameters monitored,” “acceptance criteria,” and “corrective actions” program element criteria in GALL Report AMP X.M1.

Operating Experience. LRA Section B.3.1.1 summarizes the OE related to the Fatigue Monitoring Program. The LRA includes examples of OE that provide objective evidence that the Fatigue Monitoring Program will be effective through the period of extended operation. The applicant stated that these examples show that the Fatigue Monitoring program effectively monitors plant transients, ensures actual operational transients are bounded by design transient definitions, challenges discrepancies, implements program improvements, utilizes the CAP, and proactively reviews and evaluates industry OE.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program.

The staff found no OE to indicate that the applicant’s program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and OE at the plant are bounded by those for which GALL Report AMP X.M1 was evaluated.

UFSAR Supplement. LRA Section A.3.1.1 provides the UFSAR supplement for the Fatigue Monitoring Program. The staff also noticed that the applicant committed (Commitment No. 43) to ongoing implementation of the existing Fatigue Monitoring program for managing aging of applicable components during the period of extended operation.

In its response to RAI B.3.1.1-2, by letter dated January 13, 2014, the applicant added Enhancement 4 to LRA Section A.3.1.1 to the list of enhancements for the Fatigue Monitoring program, which states:

> 4. Increase the scope of the program to include transients used in the analyses for ASME Section III fatigue exemptions, the allowable stress analyses associated with ASME Section III and ANSI B31.1, and the flaw evaluations performed in accordance with ASME Section XI, IWB-3600.

Also in response to RAI B.3.1.1-2, the applicant added Enhancement 4 to Commitment No. 43 in its License Renewal Commitment List in LRA Table A.5.

As described in the Staff Evaluation section for this AMP, the staff found the four enhancements to be acceptable. The staff also confirmed that LRA Section A.3.1.1, as amended by RAI B.3.1.1-2, includes the four enhancements to the Fatigue Monitoring program.

The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and its review of the applicant's Fatigue Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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).

3.0.3.2.25 Concrete Containment Tendon Prestress

<u>Summary of Technical Information in the Application</u>. LRA Section B.3.1.2, as revised by letter dated April 17, 2014, describes the existing Concrete Containment Tendon Prestress Program as consistent with an enhancement with the GALL Report AMP X.S1, "Concrete Containment Tendon Prestress." The program manages the loss of prestress aging effect in the prestressed concrete containment. The LRA states that the loss of containment tendon prestressing forces is a TLAA evaluated in accordance with 10 CFR 54.21(c)(1)(iii). The LRA also states that the Concrete Containment Tendon Prestress program is in accordance with Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel (B&PV) Code (ASME Code), 2001 Edition through the 2003 Addenda supplemented with the applicable requirements of 10 CFR 50.55a(b)(2)(viii)(B).

The LRA states that measurements and assessments of the loss in tendon prestressing forces over time are performed following the requirements of ASME Code Section XI, Subsection IWL. The LRA also states that the program sets the acceptance criteria for selection of tendons, predicted lower limits (PLLs) of tendon lift-off values on the forces in individual tendons, and the minimum required prestressing force or value (MRV). The LRA further states that the PLL is developed consistent with the guidance presented in RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The LRA states that if individual tendon forces remain above 95 percent of predicted values, then the actual prestressing force loss is not significantly greater than that allowed for in the original design calculations for each tendon group (dome, hoop, vertical). Furthermore, the LRA states that tendon group (dome, hoop, vertical) prestressing forces trend lines are constructed based on regression analyses of measured, individual tendon lift-off forces and represent changes in each group's prestressing force with time, consistent with NRC IN 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The LRA further states that as long as the trend lines do not fall below the MRVs prior to the next scheduled surveillance, the tendon prestress force is acceptable; if not, an evaluation will be performed in accordance with 10 CFR 50.55a(b)(2)(viii)(B) requirements before the next scheduled inspection.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP X.S1. For the "monitoring and trending," program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "monitoring and trending" program element in GALL Report AMP X.S1 recommends the construction of a regression line for trending tendon prestressing forces based on actual measured lift-off forces, following the guidance established in IN 99-10. The LRA and the onsite audited Concrete Containment Tendon Prestress AMP basis document, however, state that "[t]he trend lines, one for each tendon group, are constructed using the measured tendon forces and represent the changes in mean vertical, hoop and dome prestressing forces with time" and that "group mean forces will not fall below applicable MRVs prior to the end of the period of extended operation." According to IN 99-10:

> For a small sample size (2 percent of the [tendon] population), using the average of the measured TFs [tendon forces] at each surveillance masks the true relationship between TF [tendon force] and T [time]. Therefore, an analysis using the individual lift-off forces for the regression analysis gives results that could be statistically validated.

The staff noticed that although LRA Figures 4.5-1 through 4.5-12 show multiple tendon lift-off force values plotted for past ISIs, it uses the word "mean" when discussing the group lift-off forces. Therefore, there is a need for additional information to resolve the trending methodology used by the applicant. By letter dated March 18, 2014, the staff issued RAI B.3.1.2-1 requesting the applicant to clarify the methodology used for regression analysis for the development of statistically validated trend lines.

In its response dated April 17, 2014, the applicant clarified that the word "mean" used in LRA Appendix B.3.1.2 was not intended to imply that the methodology applied to the construction of regression analyses for Byron and Braidwood used "…the average of the [tendon force] for each surveillance test." Rather, the applicant stated, "[t]he referenced wording contained in the original LRA Appendix B, Section B.3.1.2, was intended as a characterization of what the regression analysis trend lines represent, not a description of the methodology utilized to construct the lines." The applicant also stated the following:

> The methodology used in the construction of the tendon prestress regression analyses utilizes lift-off force values for each individual tendon measured during each examination. Specifically, each individual tendon lift-off force for a tendon group (e.g., dome, hoop, vertical) measured during each examination is plotted. For each tendon group, a best-fitting linear line is applied to the entire population of data points to form a trend line. This methodology of utilizing individual tendon force values is consistent with NRC IN 99-10, and is described in LRA Section 4.5.

The applicant further stated that "in order to clarify the methodology applied to the construction of the regression analyses for BBS, LRA Section 4.5 and Appendix B, Section B.3.1.2, are revised…to remove descriptors that may imply that the methodology incorporates average force values."

The staff finds the applicant's response acceptable because it clarified that the methodology used in the construction of the tendon prestress regression analyses. It utilizes, for each tendon, the individual lift-off force values measured during each examination, resulting for each tendon group (dome, hoop, vertical) in a plotted regression line consistent with NRC IN 99-10. Therefore, the staff's concern described in RAI B.3.1.2-1 is resolved.

The staff also reviewed the portions of the "monitoring and trending" program element associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. LRA Section B.3.1.2 includes an enhancement to the "monitoring and trending" program element. The applicant stated that prior to the period of extended operation, "[f]or each surveillance interval, the predicted lower-limit, minimum required value, and trending lines will be developed for the period of extended operation as part of the regression analysis for each tendon group."

The staff reviewed the proposed enhancement and its associated commitment (Commitment No. 44) against the GALL Report "monitoring and trending," program element, which states:

> The estimated and measured prestressing forces are plotted against time, and the predicted lower limit (PLL), MRV, and trending lines are developed for the period of extended operation. NRC RG 1.35.1 provides guidance for calculating PLL and MRV. The trend line represents the trend of prestressing forces based on the actual measured forces. NRC IN 99-10 provides guidance for constructing the trend line.

The staff considered the above and noticed that when the enhancement is implemented via Commitment No. 44 and supplemented with the LRA B.3.1.2, "Concrete Containment Tendon Prestress," program description, the proposed program will be consistent with the "monitoring and trending" program element of GALL Report AMP X.S1.

Based on its audit and its review of the applicant's response to RAI B.3.1.2-1, the staff finds that program elements 1 through 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP X.S1. In addition, the staff reviewed the enhancement associated with the "monitoring and trending" program element and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.3.1.2 summarizes the Byron and Braidwood OE related to the Concrete Containment Tendon Prestress Program. The LRA states that its inspection methods being implemented by the program have been proven effective in detecting loss of containment tendon prestress. The LRA also states that review of the OE did not identify any adverse trend in program performance. According to the LRA "operating experience" program element, the program provides appropriate guidance for evaluation, repair, or replacement for locations where degradation is found. Furthermore, the LRA states that assessments of the Concrete Containment Tendon Prestress Program are performed to identify the areas that need improvement to maintain the quality performance of the program.

The LRA states that in 2009 and 2011, the applicant performed the 25th year ASME Section XI, Subsection IWL examinations of the concrete containment tendons which included testing to assess the loss of prestressing forces in randomly selected containment tendons. The LRA also states that the regression analyses document the results of all tendon prestress surveillance data through the 25th year interval. The LRA further states that in 2013, these analyses were revised to extend the trend lines to 60 years, the results of which demonstrated that the predicted prestress for all Byron and Braidwood tendon groups, will remain above the MRV for the period of extended operation. The LRA further states that monitoring of the containment tendon prestress forces to date indicate that the prestressing systems will continue to maintain their intended function through the period of extended operation without the need for tendon retensioning. The LRA states that if subsequent updates to the regression analysis, however, would indicate that the predicted prestress forces for a tendon group fall below the respective MRV, the condition would be entered into the CAP for evaluation and determination of appropriate corrective action. Therefore, the LRA concludes, "there is sufficient confidence that implementation of the Concrete Containment Tendon Prestress [P]rogram will effectively identify degradation prior to failure or loss of intended function during the period of extended operation."

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific OE were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant OE information to determine whether applicant had adequately evaluated and incorporated OE related to this program. The staff identified OE for which it determined the need for additional clarification and resulted in the issuance of an RAI as discussed below.

The OE included in the LRA and the audited plant procedure ER-AA-330-006, titled "ISI and Testing of the Prestressed Concrete Containment Post-Tensioning System" appear to differ in the frequency of tendon prestress inspections performed for each unit and site. Specifically, the LRA states that prestress tendon forces are measured every 5 years, while plant procedure ER-AA-330-006 indicates measurements being performed at alternating 10-year intervals. It is not clear whether the applicant follows the modified ISI intervals consistent with IWL-2421 and procedure ER-AA-330-006 to perform measurement of tendon forces at alternating time frames for each unit (e.g., one unit fully examined per IWL-2500 on year 20 while the other on year 25), or if it examines, tests, and measures the tendon lift-off force for both units at each site every 5 years. Therefore, by letter dated March 18, 2014, the staff issued RAI B.3.1.2-2 requesting the applicant to clarify the frequency of the prestressing tendon force measurements for each selected tendon group (dome, hoop, vertical) sample examined during ISIs for Units 1 and 2 at Byron and Braidwood.

In its response dated April 17, 2014, the applicant stated that the frequency of measuring the tendon prestressing forces for each selected tendon group (dome, hoop, vertical) sample is in accordance with the Byron and Braidwood ISI Program testing requirements. The applicant stated that examinations performed prior to the 15th year were in accordance with the modified frequency for multi-unit sites as specified in RG 1.35, "Inservice Inspection of Ungrouted Tendons in Prestress Concrete Containments." Subsequently, the applicant stated the examination frequency has been as stated in IWL-2421 for multi-unit sites, which allowed performance of the required IWL examinations at each site's two units during the same year (e.g., full IWL-2500 examinations at one unit, and IWL-2524 and IWL-2525 examinations at the other unit). The applicant also stated the following:

> [T]endon force measurements of each selected tendon group (dome, hoop, vertical) sample are currently performed once every ten (10) years per unit at each site, with the tendon force measurements for each unit being out of phase by five (5) years with respect to the other unit. Examinations performed at either Byron or Braidwood are not, however, credited for the other site.

The applicant further stated that the 25th year ASME Section XI, Subsection IWL examinations performed in 2009 at Byron and in 2011 at Braidwood included full examinations as required per IWL-2500, including prestressing tendon force measurements for each selected tendon group (dome, hoop, vertical) for their Unit 2 concrete containment structures and partial examinations as required by IWL-2524 and IWL-2525 for their Unit 1, respectively. As part of its responses, the applicant provided in its input the schedule for full (IWL-2500) and partial (IWL-2524 and IWL-2525) concrete containment IWL examinations recently completed at Byron and Braidwood and also scheduled through the 35th year.

The staff finds the applicant's response acceptable because it clarified the frequency of measuring the prestressing tendon forces for the selected tendon group (dome, hoop, vertical) sample examined during ISIs for Units 1 and 2 at Byron and Braidwood for multi-unit sites as required by IWL-2421. The staff's concern described in RAI B.3.1.2-2 is resolved.

Based on its audit, its review of the application, and review of the applicant's response to RAI B.3.1.2-2, the staff finds that the applicant has appropriately evaluated plant-specific and industry OE and that implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds conditions and OE at the plant are bounded by those for which GALL Report AMP X.S1 was evaluated.

UFSAR Supplement. LRA Section A.3.1.2 provides the UFSAR supplement for the Concrete Containment Tendon Prestress Program. The staff reviewed this UFSAR supplement description of the program and noticed that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noticed that the applicant committed to develop for each surveillance interval, the PLL, MRV, and trending lines as part of the regression analysis for each tendon group for the period of extended operation. The staff also noticed that the applicant committed to implement the enhancement to the program prior to the period of extended operation. The staff finds that the information in UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and its review of the applicant's Concrete Containment Tendon Prestress Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant 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 Affected by Loss of Coating Integrity for Internal Coatings on In-Scope Piping, Piping Components, Heat Exchangers and Tanks

3.0.3.3.1 Staff Evaluation of Aging Management Program Changes Associated with Managing Loss of Coating Integrity for Internal Coatings on In-Scope Piping, Piping Components, Heat Exchangers and Tanks

Staff Evaluation. After the LRA was submitted, based on reviews of industry OE and several LRAs, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letter dated December 13, 2013, the staff issued RAI 3.0.3-2 requesting that the applicant address how loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage will be managed if coatings have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks).

Staff's Recommended Actions to Manage Loss of Coating Integrity for Internal Coatings of Piping, Piping Components, Heat Exchangers, and Tanks. The staff has determined that additional recommendations beyond those in the GALL Report are appropriate to manage loss of coating integrity for internal coatings of piping, piping components, heat exchangers, and tanks. The staff has concluded that the following recommended actions provide one acceptable approach for managing the associated aging effects for components within the scope of license renewal. Throughout the remainder of this SER Section, the statement, "staff's recommended actions to manage loss of coating integrity," is in reference to this subsection of the SER. The staff concluded the following:

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

although indicators of some degree of coating degradation, are not significant enough to require more frequent inspections as long as the condition has been found acceptable by qualified personnel. For example, despite cracking being found, the base metal could still be isolated from the environment and the coating retain sufficient integrity so as not to become debris.

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

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

d. Given that the coatings installed on the internal surfaces of diesel fuel oil storage tanks are generally exposed to a static environment, the inspection interval may be conducted in accordance with GALL Report AMP XI.M30, "Fuel Oil Chemistry," as long as the inspection results meet a, above.

- The extent of inspections should include all accessible tank and heat exchanger internal surfaces. The staff recognizes that, for piping, extensive amounts of coating could be installed. GALL Report AMPs such as XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," are based on sampling a portion of the population. The staff concludes that using a sampling based extent of inspections is appropriate for coatings installed on the internal surfaces of piping. Where documentation exists that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants" or earlier versions of those standards) were used during installation, the extent of piping inspections may be 25 1-foot axial length circumferential segments of piping or 20 percent of the total length of each coating material and environment combination. This extent of sampling is consistent with several GALL Report AMPs. However, where documentation does not exist that manufacturer recommendations and industry consensus documents were used during installation, the staff concludes that a larger extent of inspection is appropriate, consisting of 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination. Regardless of the extent of inspections, the inspection surface includes the entire inside surface of the 1-foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments is increased in order to cover an equivalent length.

- The staff concludes that, where loss of coating integrity cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components, a representative sample of external wall thickness measurements can be used to confirm the acceptability of the corrosion rate of the base metal in lieu of visual inspections of the coating. The wall thickness measurements are an appropriate method to manage loss of coating integrity in this case because base metal corrosion is the only effect of loss of coating integrity.

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

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

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

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

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

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

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

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

- Coatings that do not meet acceptance criteria should be repaired or replaced. Testing or examination is conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating material. These recommendations are consistent with ASTM D7167-05, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant," which is referenced in RG 1.54.

In its response dated January 13, 2014:

- The applicant stated that the scope of SSCs that have internal coatings includes: specific heat exchangers cooled by the service water system, EDG fuel oil storage tanks, foam concentrate tanks and galvanized portions of the fire protection system, lined lubricating oil reservoirs, components associated with the caustic and acid supply to the radwaste system demineralizers that are not in service, components associated with hypochlorite injection to the discharge of the essential service water pumps that are not in service, and the 0C auxiliary building chiller condenser at Byron that is not in service.
- The applicant stated the basis for why the following SSCs do not require visual inspections of the coatings to prevent or mitigate unanticipated or accelerated corrosion of the base metal and/or degraded performance of downstream equipment due to flow blockage (e.g., reduction in flow, increased pressure drop, reduction in heat transfer) as follows:
    - Galvanized piping associated with the CO_2-based fire suppression subsystems is not expected to degrade because the environment is a dry gas. Loss of coating integrity causing degraded performance of downstream equipment due to flow blockage is not expected to occur for galvanized piping in a dry gas environment.

      The staff finds this acceptable because based on its review of recent industry OE and several LRAs, the staff concludes that only water-filled systems warrant augmented inspections to address loss of coating integrity. The base metal in dry gas systems is not expected to lose material to the point where the CLB functions would not be met. In addition, degraded galvanized coating would not be expected to accumulate and cause flow blockage.
    - Galvanized piping associated with the water-based fire suppression subsystems is susceptible to age-related degradation. However, galvanized piping is not subject to unanticipated or accelerated corrosion of the base metal due to coating holidays. In the case of galvanized steel, since zinc has a lower electrode potential than steel, the zinc coating acts as a large sacrificial anode coupled with a small cathode where the steel substrate is exposed in the coating holiday. Since there is a relatively small cathode surface and a relatively large anode surface, there is no accelerated corrosion because the remaining zinc acts as a sacrificial anode to the base metal and provides cathodic protection for

the exposed surfaces of the piping for a long period of time. In addition, degraded performance of downstream equipment due to flow blockage is not expected to occur for galvanized piping since the zinc coating dissolves into solution as it degrades and does not delaminate, blister, crack, flake, or peel.

The staff does not agree with the applicant in regard to the potential for unanticipated or accelerated corrosion of the base metal. Information Notice 2013-06, 'Corrosion in Fire Protection Piping Due to Air and Water Interactions,' described a 6-in. fire main where the lower portions of the galvanized piping exposed to water had corroded. However, as required by the Fire Water System program, see SER Section 3.0.3.2.11, periodic internal visual inspections of fire water system piping are conducted by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line in each structure containing in-scope water-based fire suppression systems. The staff finds the applicant's response in regards to accelerated corrosion acceptable because these inspections are capable of detecting loss of material due to potential loss of the galvanized coating. The staff finds the applicant's response in regard to flow blockage acceptable because degraded galvanized coating would not be expected to accumulate and cause flow blockage.

- The lubricating oil reservoirs for the safety injection pumps at Byron and Braidwood have internal linings, which will be managed by the Lubricating Oil Analysis program. The program includes oil sampling and oil change activities that are capable of detecting coating degradation. The oil sampling associated with the program includes testing for particulate in the oil, which would indicate degradation of the internal lining of the reservoir or of the base metal, and therefore no additional inspections of the internal linings of the lubricating oil reservoirs are warranted.

  The staff recognizes that oil samples taken from the safety injection pump oil reservoir are capable of detecting particulate from degraded coatings or corrosion products where bare metal had been exposed. However, debris from coating degradation generated between samples could reduce the flow to the pump bearings and result in the loss of the pump's CLB intended function(s). Additionally, oil changes could result in removing evidence of gradual coating degradation. It was not clear to the staff that the internal coated surfaces of the safety injection pump oil reservoir will be in the sample population of the One-Time Inspection Program for components exposed to lubricating oil. In addition, it was not clear to the staff whether a one-time inspection is appropriate for this coating as it continues to age. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (1) requesting that the applicant state: (a) the basis for why debris from coating degradation generated between samples will not result in flow blockage of the oil supply to the safety injection pump bearings, (b) the basis for why oil changes will not result in reduced sensitivity to gradual coating degradation, (c) whether the internal coated surfaces of the safety injection pump oil reservoir will be in the sample population of the One-Time Inspection Program for components exposed to lubricating oil, and (d) the basis for why a one-time inspection is appropriate for this coating.

  In its response dated May 5, 2014, the applicant stated the oil is sampled every 3 years; however, the system includes an oil filter that removes debris and particulate (greater than 130 microns) prior to the oil reaching the bearings. The differential pressure across the oil filter is monitored during quarterly surveillances of the pumps. The applicant also stated that the internal surfaces of the oil reservoirs will be in the sample population of the One-Time Inspection Program. The applicant further stated that the one-time inspection is appropriate because it is supplemented with ongoing monitoring during quarterly surveillance tests.

The staff finds the applicant's response acceptable because monitoring the differential pressure across the oil filter on a quarterly basis (much more frequent than oil sampling on a 3-year basis) provides reasonable assurance that coating degradation would be detected prior to loss of the CLB intended functions of the safety injection pumps and that the one-time inspection will detect any potential gross degradation of the coatings. However, neither the applicant's UFSAR supplement nor program credits the monitoring of the differential pressure across the oil filter. By letter dated May 29, 2014, the staff issued RAI 3.0.3-2b Request (3) requesting that the applicant revise LRA Sections A.2.1.26 and B.2.1.26 to credit monitoring the differential pressure across the oil filter.

In its response dated June 30, 2014, the applicant revised LRA Sections A.2.1.26 and B.2.1.26 to credit the existing activities related to the measurement of differential pressure across the safety injection pump lubricating oil system oil filter, performed during quarterly surveillance testing of the pumps, for aging management.

The staff finds the applicant's response acceptable because the Lubricating Oil Analysis program and UFSAR supplement appropriately reflect that monitoring the differential pressure across the safety injection pump lubricating oil system oil filter is credited as a required activity during the period of extended operation. The staff's concern described in RAI 3.0.3-2b Request (3) is resolved.

- The components associated with the caustic and acid supply to the radwaste system demineralizers, components associated with hypochlorite injection to the discharge of the essential service water pumps, and the 0C auxiliary building chiller condenser at Byron are not in service and are not exposed to an aggressive internal environment. Disbonded coatings could not cause degraded performance of downstream equipment because there is a closed valve between the lined/coated components and downstream inservice equipment. Visual inspections of these components will be performed in accordance with the requirements of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, which will include assessment of the condition of the internal coatings or linings.

  The staff had the following concerns in relation to use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of coating integrity for these components: (a) the program is based on a 10-year inspection frequency; whereas the staff has concluded that the maximum inspection interval should be 6 years, 4 years, or 2 years depending on the conditions detected during inspections and whether the coatings have been recently repaired or replaced; (b) it was not clear to the staff whether the coated steel components would be considered as a unique sample population, which would ensure that a minimum sample of coated components would be inspected under the program; (c) the staff has concluded that the UFSAR supplement for programs that will manage loss of coating integrity should include key aspects of the program associated with coating degradation, such as followup testing that will be conducted when degradation is determined to not meet acceptance criteria, and the basis for the training and qualification of individuals involved in coating inspections, whereas, these aspects are not in LRA Section A.2.1.25; and (d) the staff has concluded that the programs credited for detecting loss of coating integrity should include a summary description in the LRA of: when baseline inspections will be conducted, the extent of inspections, qualifications for individuals performing activities associated with coating inspections, a summary description of how monitoring and trending of the coatings will be conducted, acceptance criteria, and a summary description of corrective actions when coating degradation is detected, whereas, these details are not in LRA Section B.2.1.25 for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

In addition, the staff found that LRA Sections A.2.1.11 and B.2.1.11 for the Open-Cycle Cooling Water System Program, and A.2.1.18 and B.2.1.18 for the Fuel Oil Chemistry program (as stated below, these programs are credited for coatings inspections) lack sufficient specificity. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (2) requesting that the applicant state: the basis for why a 10-year inspection frequency is adequate and whether coated steel components will be considered as a unique sample population.

In its response dated May 5, 2014, the applicant stated that there is no need to incorporate coating inspection activities into the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. In regard to use of this program to manage loss of coating integrity for components associated with the caustic and acid supply to the radwaste system demineralizers, components associated with hypochlorite injection to the discharge of the essential service water pumps, and the 0C auxiliary building chiller condenser at Byron, the applicant stated the following: (a) the components only perform an intended function to maintain the leakage boundary, as described on 10 CFR 54.4(a)(2); (b) the coatings were installed to mitigate the environmental impact (i.e., acid compounds, caustic compounds, hypochlorite, turbulence due to flow) if the components had been left in service; and to protect the base metal from the relatively slow corrosion expected due to the environment the equipment would have been exposed to had the system been put in service; (c) credit was not taken for the presence of protective coatings when determining applicable AERMs; (d) based on the system designs, there is no potential for a strong galvanic cell to exist if localized coating degradation were to occur; (e) the coated components represent a unique sample population in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

The applicant revised LRA Sections A.2.1.11 and A.2.1.18 to state that followup testing in the Open-Cycle Cooling Water and Fuel Oil Chemistry programs will be conducted when coating degradation is determined to not meet acceptance criteria and the programs were enhanced to state the basis for the training and qualification of individuals involved in coating inspections.

The applicant also revised LRA Sections B.2.1.11 and B.2.1.18 to state: (a) that at least one baseline inspection of each diesel oil storage tank and service water cooled heat exchanger will be performed during the 10-year period prior to the period of extended operation; (b) that 100 percent of accessible coated surfaces after component disassembly or entry of components will be inspected; (c) that coating inspectors will be certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54; (d) a summary of monitoring and trending parameters; (e) acceptance criteria; and (f) a summary of corrective actions.

Regarding the out-of-service systems, the staff noticed that, given that these systems are isolated, in-leakage would have a similar environmental impact as waste water as defined in GALL Report Section IX.D (waters that are collected from equipment and floor drains). The staff finds the applicant's response associated with the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of coating integrity for the above cited components acceptable because: (a) the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is recommended by GALL Report item AP-281 to manage loss of material for steel components exposed to waste water; (b) the likelihood of accelerated corrosion is low because there are no corrosive chemicals in the environment and no significant galvanic couplings; (c) flow blockage affecting active systems is not possible because the applicable portions of the systems are isolated from active systems; and (d) periodic internal visual inspections will occur.

The staff finds the applicant's response associated with the level of detail in the UFSAR supplements and aging management programs for the Open-Cycle Cooling Water System and Fuel Oil Chemistry programs acceptable because the appropriate level of detail has been incorporated. The staff's concern described in RAI 3.0.3-2a Request (2) is resolved.

- The applicant stated that, for the specific heat exchangers cooled by the service water system, EDG fuel oil storage tanks, foam concentrate tanks and galvanized portions of the fire protection system, internal coatings will be visually inspected for signs of erosion, cracking, flaking, peeling, blistering, delamination, rusting, and mechanical damage.

  The staff finds the applicant's proposed use of visual inspections for the cited aging effects acceptable because the inspection method and aging effects are consistent with the staff's recommended action to manage loss of coating integrity.

- The applicant stated that the inspections of coatings will be conducted as part of the Open-Cycle Cooling Water System (specific heat exchangers cooled by the service water system), Fuel Oil Chemistry (EDG fuel oil storage tanks), and the Fire Water System (foam concentrate tanks) programs. The staff's evaluation of the changes to each of these programs to address loss of coating integrity follows.

  - The applicant stated that inspections of coated heat exchangers cooled by the service water system are performed every 2 to 6 years, depending on the heat exchanger, and will continue through the period of extended operation. The inspection frequency for individual heat exchangers is based on the criticality of the component, prior inspection results, and service conditions.

    The staff has concluded that, when peeling, delamination, blisters, rusting, cracking, or flaking has been detected during coating inspections, subsequent inspection intervals are established by a qualified coating specialist; however, the staff has concluded that intervals should not exceed every other refueling outage interval. The applicant's proposed 6-year inspection interval exceeds the every other refueling outage interval. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (3) requesting that the applicant state the basis for why it can be concluded that there is reasonable assurance that loss of coating integrity will not result in accelerated degradation caused by localized coating failures or degraded downstream component performance due to flow blockage when: (a) prior component inspections detected peeling, delamination, blisters, rusting, cracking, or flaking, and (b) subsequent inspections will exceed two refueling outage intervals.

In its response dated May 5, 2014, the applicant stated the heat exchangers were operated for over 10 years without coatings and that a corrosion allowance was established during this time period. Minimum wall thickness requirements based on design requirements and observed corrosion rates ensure that loss of intended function will not occur between inspections even if the coating were to fail. Based on design, dissimilar metal contact will not cause a strong galvanic cell capable of causing accelerated corrosion of the base metal such that loss of function of the component will occur prior to the next scheduled inspection. A review of plant-specific OE (over 150 inspections performed over the past 10 years) has demonstrated that the inspection intervals are adequate. The applicant also stated that the CeramAlloy™ coating has been used for approximately 17 years and is currently installed in over 60 heat exchangers. Based on a review of plant-specific OE, when the coating is properly installed, delamination or peeling does not occur. Age-related degradation to date indicates that the coating flakes or chips off in small pieces due to the erosive effects of turbulent service water and passes out of the heat exchanger. A search of the Institute of Nuclear Power Operations industry-wide OE database did not identify any age-related failures of CeramAlloy™ which caused flow blockage of downstream components. Coating application and repair for the service water cooled heat exchangers is performed by qualified coating applicators in accordance with plant-specific procedures with guidance for the preparation of the base metal and application of the coating.

The staff noticed that, based on a review of the vendor's information, ENECON, CeramAlloy™ is a two component polymer used to repair, resurface and coat components to provide erosion and corrosion resistance. It can be applied by brush, roller or flexible applicator and cures to a hard ceramic-like material with a smooth surface. Based on the composition of the coating and application methodology, the staff concludes that this material is similar to other commonly used coatings that have not demonstrated sheet-like failure. Therefore, there is reasonable assurance that the coating will not fail in a sheet-like manner as long as appropriate installation techniques are followed (e.g., surface preparation, cure time).

The staff finds the applicant's response acceptable because, although the interval to subsequent inspections could be longer than that recommended in the staff's recommended actions to manage loss of coating integrity, there is reasonable assurance that the internally coated heat exchangers cooled by the service water system will be capable of performing their CLB intended functions. Specifically: (a) minimum wall thickness requirements will be met considering a corrosion allowance based on plant-specific OE even with bare metal exposure between inspections; (b) the potential for accelerated corrosion is very low because by design, potential dissimilar metal contact will not cause a strong galvanic cell to be formed; (c) coating application and repair is performed by qualified coating applicators in accordance with plant-specific procedures; and (d) based on the staff's review of the specific coating material, it is unlikely that large particles would be generated if the coating degraded; and therefore, flow blockage of downstream components is unlikely. The staff's concern described in RAI 3.0.3-2a Request (3) is resolved.

The applicant stated that inspections of the diesel oil storage tank coatings will be performed at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation as part of the visual inspections of the internal surface of the diesel oil storage tanks required by the Fuel Oil Chemistry program. The 10-year inspection frequency is consistent with the guidance provided in EPRI TR-1019157, "Guideline on Nuclear Safety-Related Coatings," Revision 2.

The staff has concluded that coating inspections for diesel oil storage tanks may be conducted at the frequency stated in the Fuel Oil Chemistry program as long as: (a) no peeling, delamination, blisters, or rusting are observed during inspections, and (b) any cracking and flaking has been found acceptable by a coating specialist. If this is not the case, inspections should be conducted more frequently. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (4) requesting that the applicant state the periodicity of inspections for the diesel oil storage tank internal coatings, and basis for the periodicity of inspections, if the prior inspection detected peeling, delamination, blisters, rusting, or unacceptable cracking and flaking.

In its response dated May 5, 2014, the applicant stated that a review of the results of completed tank inspections indicates that significant coating peeling, delamination, blistering, rusting, or unacceptable cracking and flaking has not occurred. In addition, an internal inspection of the Braidwood 2A diesel oil storage tank performed in 2008 revealed a section of the coating missing from original construction, and there were no indications of loss of material were identified at the location of the missing coating. The diesel oil storage tanks are designed such that coating debris will not cause flow blockage of downstream components because the suction lines for the fuel oil transfer pumps are located greater than a foot above the bottom of the tanks and the tank bottoms are sloped such that any debris would accumulate away from the suction line for the fuel oil transfer pumps.

The staff does not find the applicant's response acceptable because the applicant did not provide sufficient details for the staff to conclude that a 10-year inspection interval for the tanks is acceptable. For example: (a) even though the tank is sloped and the suction lines are a foot above the tank bottom, depending on the specific gravity of coating debris and the flow velocity, debris could be transported; (b) although corrosion is unlikely for bare metal exposed to fuel, debris and water can collect on the tank bottom and result in loss of material, and the RAI response did not address design minimum wall thickness and corrosion allowances; and (c) current inspections are not necessarily an effective indicator of degradation that could occur in the period of extended operation. By letter dated May 29, 2014, the staff issued RAI 3.0.3-2b Request (1) requesting that the applicant provide sufficient information for the staff to conclude that neither loss of material or coating debris would result in loss of the CLB intended functions of the tanks and downstream in-scope components.

In its response dated June 30, 2014, the applicant stated that the basis for determining that neither loss of material nor coating debris would result in in loss of the current licensing basis intended functions of the tanks and downstream in-scope components is as follows: (a) the potential for accumulation of significant quantities of water, which could lead to loss of material in the tank, is low due to the quality of the fuel oil that is added to the tanks, quarterly samples to confirm the oil quality, the indoor location of the tanks that results in minimal temperature cycles and thus a lower potential for significant water intrusion, and the fact that tanks are periodically drained, cleaned, and internally inspected; (b) plant-specific OE demonstrated that there was no loss of material in areas where there was missing coating; (c) the tanks have level instrumentation and alarms to provide indication that leakage is occurring; (d) flow blockage of downstream components due to debris is not expected because the suction lines for the fuel oil transfer pumps are located greater than a foot above the bottom of the tanks, the tank bottoms are sloped such that any debris would accumulate away from the suction line for the fuel oil transfer pumps, and the suction piping for the fuel oil transfer pumps, located downstream from the emergency diesel generator fuel oil storage tanks, are each equipped with strainers to ensure any debris is removed prior to the fuel oil reaching the emergency diesel generator day tanks. The applicant also stated that the strainers are provided with differential pressure instrumentation and high differential pressure alarms. The applicant further stated that the fuel oil transfer system is tested at least once every 2 years and each diesel generator is tested monthly, during which the strainer differential pressure is monitored continuously via the high differential pressure alarm during the fuel oil transfer system testing and during the emergency diesel generator testing. LRA Sections A.2.1.18 and B.2.1.18 were revised to credit the monitoring of the instrumentation and alarms associated with the fuel oil transfer pump suction strainer differential pressure.

The staff finds the applicant’s response and the use of the Fuel Oil Chemistry program to inspect diesel oil storage tank internal coatings acceptable because the staff concludes that there is reasonable assurance that loss of coating integrity will not result in loss of material or flow blockage to the degree that it would impact the current licensing basis intended functions of the emergency diesel generators or fuel oil transfer system. The staff concludes this in regard to loss of material based on the low potential for a corrosive environment in the fuel oil storage tank as described by the applicant. The staff concludes this in regard to flow blockage because of the frequent opportunities to monitor the fuel oil transfer pump suction strainer differential pressure, which would provide indication if coating particles were transporting from the tank. The staff's concern described in RAI 3.0.3-2b Request (1) is resolved.

- o The applicant stated that the foam concentrate tanks are coated steel tanks with an internal bladder that contains the foam concentrate. It is not possible for failed coatings to result in degraded performance of downstream equipment due to flow blockage as long as the bladder remains intact. Inspections of the coatings for the foam concentrate tanks are performed every 15 years during replacement of the internal bladder. This inspection frequency is appropriate based on the consequence of coating degradation and prior inspection results.

  The staff noticed that LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," AMP XI.M27, Table 4a, "Fire Water System Inspection and Testing Recommendations," recommends that foam water system storage tanks be visually inspected for internal corrosion every 10 years. The staff also noticed that the bladder separates the tank internals from the corrosive foam concentrate. The staff further noticed that Enhancement No. 6 for the Fire Water System program revised the inspection interval of the tank to every 10 years. The staff finds the applicant's proposal acceptable because the bladder isolates the coated tank from aggressive chemicals and because any potential coating debris would accumulate outside of the bladder and would not be introduced into the foam discharge path. However, the staff noticed that the Fire Water System UFSAR supplement does not include key details and that the program does not include summary descriptions of activities associated with managing loss of coating integrity as described in RAI 3.0.3-2a Request (2), above. By letter dated May 29, 2014, the staff issued RAI 3.0.3-2b Request (4) requesting that the applicant provide a similar level of detail in the Fire Water System UFSAR supplement and program as described in the response to RAI 3.0.3-2a Request (2).

  In its response dated June 30, 2014, the applicant revised LRA Sections A.2.1.16 and B.2.1.16 to include key aspects of the program and summary descriptions of activities associated with managing loss of coating integrity.

  The staff finds the applicant's response acceptable because, based on a review of the changes and enhancements to LRA Sections A.2.1.16 and B.2.1.16, the Fire Water System program includes the key aspects associated with managing loss of coating integrity consistent with the staff's recommended actions to manage loss of coating integrity such as qualification of coating inspectors, followup physical testing requirements, and acceptance criteria (Section B.2.1.16 only). The staff's concern described in RAI 3.0.3-2b Request (4) is resolved.

- The applicant stated that, upon component disassembly, visual inspections will be conducted on 100 percent of all accessible surfaces. LRA Tables 3.3.2-20 and 3.3.2-22 state that loss of coating integrity is being managed for piping and piping components.

  While the statement that 100 percent of the coated surfaces that are accessible upon component disassembly are visually inspected each inspection interval is clear in relation to tanks and heat exchangers, it does not provide sufficient clarity for inspections of piping and piping components. The staff has concluded that for piping and piping components, either 73 representative 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination should be inspected in each interval. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (5) requesting that the applicant state the minimum inspection size and its basis for internally coated piping and piping components.

In its response dated May 5, 2014, the applicant stated that the only internally coated piping, piping components, and piping elements within the scope of license renewal are those discussed in the response to RAI 3.0.3-2a Request (2), above, for which aging effects will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and the minimum inspection sample size in the staff's recommended actions to manage for loss of coating integrity is not applicable.

The staff finds the applicant's response acceptable because, based on the staff's evaluation of the response to RAI 3.0.3-2a Request (2), above, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program's sample size is not required to be revised in order to address loss of coating integrity. The staff's concern described in RAI 3.0.3-2a Request (5) is resolved.

- The applicant stated that inspections of Service Level III coatings are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." Inspection reports are provided to the site coatings coordinator. The site coatings coordinator will be qualified in accordance with ASTM D 7108-05, "Standard Guideline for Establishing Qualifications for a Nuclear Coating Specialist." Inspections of Service Level II coatings are performed by system managers or maintenance personnel utilizing procedural guidance. Personnel performing inspections are qualified in accordance with the INPO National Academy for Nuclear Training accredited training program that meets industry standards described in ACAD 92-008, "Guidelines for Training and Qualification of Maintenance Personnel."

  The staff has concluded that ANSI N45.2.6 certification is an acceptable basis for qualifying coatings inspectors based on RG 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants, June 1973, Section C.1, which mandates conformance to the ANSI N45.2 QA standards. Subsequent revisions of RG 1.54 endorsed ASTM standards that specifically address inspector qualifications as they were released to industry.

  However, it appears to the staff that the reference to Service Level II coatings (nonsafety-related coatings) would encompass coatings applied to the internal surfaces of components described in the RAI response. The staff has concluded that any coatings applied to the internal surfaces of an in-scope component where degradation of the coating could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3) should be inspected by personnel qualified in accordance with a standard endorsed in RG 1.54. While the staff has reviewed and endorsed the use of ANSI N45.2.6 as well as ASTM standards referenced in RG 1.54 for inspection personnel, it has not reviewed and endorsed ACAD 92-008. In addition, it was not clear to the staff that system managers would be qualified in accordance with an ACAD standard for training maintenance personnel. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (6) requesting that the applicant state the qualification requirements included in the system manager and maintenance personnel INPO accredited training programs that establish proficiency in coating inspections.

In its response dated May 5, 2014, the applicant revised the Open-Cycle Cooling Water System and Fuel Oil Chemistry Programs and UFSAR supplements and included enhancements to require that coating inspectors are certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54.

The staff finds the applicant's response acceptable because using personnel qualified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54 to conduct coating inspection activities is consistent with the staff's recommended actions to manage loss of coating integrity. The staff's concern described in RAI 3.0.3-2a Request (6) is resolved.

- The applicant stated that the as-found condition of the coating is documented in inspection reports. The results of previous inspections are used to determine changes in the condition of the coating over time. Trending of coating degradation is utilized to establish appropriate inspection frequencies for components with internal coatings. The frequency of coating inspections is based, in part, on the results of prior inspections. These frequencies are chosen such that coating degradation is identified before degradation of the base metal occurs such that intended functions of the coated component are maintained.

  The staff has concluded that the coatings specialist should prepare a post-inspection report to include: a list and location of all areas evidencing deterioration; a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage; and where possible, photographic documentation indexed to inspection locations. The RAI response did not provide this specificity. The post-inspection report should be compiled or approved by a coatings specialist, and it should include sufficient information to ensure that degraded areas are appropriately dispositioned through the CAP and that future inspection locations are selected based on known areas where degradation has occurred. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (7) requesting that the applicant state the qualifications of the individual who will approve post-inspection reports and the key information that will be included in the report.

  In its response dated May 5, 2014, the applicant stated that post-inspection reports will be prepared by coating inspectors that are certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54 and reviewed by the Site Coating Coordinator who will be qualified as a coating specialist in accordance with the requirements of ASTM D7108. The report will include areas or items exhibiting coating degradation, including photographs, and recommendations for immediate coating repair or replacement prior to returning the system to service or postponement of coating repair or replacement to the next inspection window. The staff finds the applicant's response to RAI 3.0.3-2a Request (7) acceptable in part because it is consistent with staff's recommended actions to manage loss of coating integrity. However, the staff noticed that the applicant had not included summary of the report contents in the Open-Cycle Cooling Water, Fuel Oil Chemistry, and Fire Water System programs. By letter dated May 29, 2014, the staff issued RAI 3.0.3-2b Request (5) requesting that the applicant include the key information that will be included in the reports in the above programs. The staff also requested that the applicant include a summary description of the qualifications of the individual who will approve post-inspection reports for coatings in the Fire Water System program.

  In its response dated June 30, 2014, the applicant revised LRA Sections B.2.1.11, B.2.1.16, and B.2.1.18 to specify the key information that will be included in the post-inspection reports. In addition, LRA Section B.2.1.16 was revised to specify the qualifications of the individual who will approve post-inspection reports for coatings.

The staff finds the applicant's response acceptable because the details of what is included in the post-inspection report and the qualifications of the individual who will approve post-inspection reports for coatings in the Fire Water System program is consistent with the staff's recommended actions to manage loss of coating integrity. The staff's concern described in RAI 3.0.3-2b Request (5) is resolved.

- The applicant stated that inspections are performed for signs of coating failures and precursors to coating failures including erosion, cracking, flaking, peeling, blistering, delamination, rusting, and mechanical damage. Any loss of coating integrity such that loss of material of the base metal occurs is considered a coating failure. Localized areas of loss of coating integrity without subsequent loss of material of the base metal are considered acceptable. Plant-specific OE has shown that these acceptance criteria are adequate to ensure the intended function(s) of the coated components, and, if applicable, downstream components are maintained.

  The staff has concluded that:

  - Indications of peeling and delamination are not acceptable and the coatings should be repaired or replaced. For coated surfaces that show evidence of delamination or peeling, physical testing should be performed where physically possible (i.e., sufficient room to conduct testing). The test should consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in RG 1.54. A minimum of three sample points adjacent to the defective area should be tested.
  - Blisters should be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. The cause of blisters should be determined if the blister is not repaired. Physical testing should be conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. If coatings are credited for corrosion prevention, the component's base material in the vicinity of the blister should be inspected to determine if unanticipated corrosion has occurred.
  - Indications such as cracking, flaking, and rusting should be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard.

  The response to the RAI is not consistent with the staff's position. For example, (a) the program would allow peeling or delamination as long as it was not accompanied with loss of base material; (b) there is no indication that a coatings specialist would evaluate blisters, cracking, flaking, or rusting; and (c) there is no indication that followup physical testing would be conducted when delamination, peeling, or blistering is detected. While the response stated that plant-specific OE has shown that the acceptance criteria are adequate, no specific information was provided to justify the statement. By letter dated April 3, 2014, the staff issued RAI 3.0.3-2a Request (8) requesting that the applicant state: (a) the specific basis for why peeling, delamination, blisters, cracking, flaking, or rusting, which does not result in loss of material of the base metal, will not result in loss of function of a component due to accelerated corrosion or degradation of downstream component performance prior to the next inspection interval; (b) the qualifications of the individual who will evaluate indications of blisters, cracking, flaking, or rusting; and (c) whether followup physical testing will be conducted when delamination, peeling, or blistering is detected, and if not, the basis for not performing physical testing.

In its response dated May 5, 2014, the applicant stated that: (a) LRA Sections A.2.1.11, A.2.1.18, B.2.1.11, and B.2.1.18 will be enhanced to state that signs of delamination of the coating from the base metal (e.g., peeling and blistering) are not acceptable and physical testing, where physically possible, will be conducted; and (b) individuals that will evaluate coating degradation will be qualified coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54.

The staff finds the applicant's response acceptable in part because the individuals that evaluate coating degradation will be appropriately qualified and followup physical testing when delamination, peeling, or blistering is detected will ensure that sound coatings remain in service either at the interface to a repair or in the area surrounding a blister. However, the changes to the Open-Cycle Cooling Water System and Fuel Oil Chemistry programs and UFSAR supplements are internally inconsistent. The staff noticed that one portion would allow degraded coatings that exhibit delamination and peeling to remain in service, while the enhancements state that signs of delamination of the coating from the base metal (e.g., peeling and blistering) are not acceptable. In addition, peeling, delamination, and blistering are intermixed, resulting in unclear guidance. By letter dated May 29, 2014, the staff issued RAI 3.0.3-2b Request (2) requesting that the applicant clarify the Open-Cycle Cooling Water System and Fuel Oil Chemistry programs and UFSAR supplements in regard to acceptability of peeling, delamination and blistering.

In its response dated June 30, 2014, the applicant enhanced LRA Sections B.2.1.11, B.2.1.16, and B.2.1.18 to state: (a) the acceptance criteria will specify that peeling, blistering, and delamination is not acceptable; (b) peeling, blistering, or delamination of the coating from the base metal will be entered into the corrective action program; (c) if the coating is not repaired or replaced, physical testing will be conducted to ensure that the remaining coating is tightly bonded to the base metal; (d) if the coating is not repaired or replaced, the potential for further degradation of the coating will be minimized "(i.e., any loose coating is removed, the edge of the remaining coating is feathered)"; (e) adhesion testing using ASTM International standards endorsed in RG 1.54 will be conducted at a minimum of 3 sample points adjacent to the defective area; (f) a certified coatings inspector will assess indications of blisters, cracking, flaking, or rusting and document the condition and acceptance in a post-inspection report; and (g) if coatings exhibiting signs of peeling, blistering, or delamination will be returned to service without repair or replacement, the applicant will conduct an evaluation of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material of the coated component. The applicant also stated that, as stated in the response to RAI 3.0.3-2a, the environment for coated components is not aggressive enough to cause accelerated corrosion of the base metal.

The staff has concluded that immersion coatings that have exhibited delamination or peeling should be repaired or replaced prior to returning the affected component(s) to service unless the degraded coating: (a) has been inspected, tested, evaluated, and partially corrected to minimize the potential for propagation, as described above; and (b) is visually inspected by the end of the next refueling outage and then again by the end of the following refueling outage to ensure that the delamination or peeling is not propagating. However, the staff noticed that the applicant did not include the followup coatings inspections in its programs.

By letter dated August 4, 2014, the staff issued RAI 3.0.3-2c requesting that the applicant address corrective actions associated with coatings exhibiting peeling or delamination, which will not be repaired or replaced prior to returning the affected component(s) to service.

In its reply dated August 29, 2014, the applicant stated that:

> if a coating exhibiting signs of peeling or delamination is not repaired or replaced prior to returning the coated component to service, then either: (1) repair or replacement of the coating will be performed within two years from when the degraded condition was detected, or (2) follow-up inspections of the degraded coating will be performed within two years from when the degraded condition was detected and then again by the end of the following two-year interval to verify that the delamination or peeling is not propagating.

The staff noticed that the applicant revised LRA Sections B.2.1.11, B.2.1.16, and B.2.1.18 to include the above followup actions. The staff finds the applicant's responses acceptable because the applicant will confirm through physical testing that the remaining coating is tightly bonded to the base metal; the coating degradation will be mitigated so as to limit the potential for further degradation; an evaluation will be conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material of the coated component; and either the degraded coating will be repaired or replaced or subsequent inspections sufficient to confirm the condition of the coating will be conducted. As a result, there is assurance that degraded coatings will not come loose and result in flow blockage. In regard to loss of material of the base metal, the staff finds the applicant's responses acceptable because the environment is not likely to cause accelerated corrosion and the followup inspections will either confirm this or result in the applicant entering the condition in its corrective action program.

- The applicant stated that evaluations are performed for inspection results that do not satisfy established criteria and the conditions are entered into the CAP. The CAP ensures that conditions adverse to quality are promptly corrected. If appropriate, corrective actions may include coating repair prior to the component being returned to service.

  The staff finds the applicant's statement acceptable because the CAP will be used to document conditions that do not meet acceptance criteria.

The staff noticed that the applicant revised the programs and UFSAR supplements for the Open-Cycle Cooling Water System, Fuel Oil Chemistry, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Lubricating Oil Analysis programs and LRA Tables 2.3.3-22, 3.2.2-4, 3.3.2-12, 3.3.2-15, 3.3.2-20, 3.3.2-22, and 3.4.2-1 to reflect the above changes.

On the basis of its review of the proposed changes to the Open-Cycle Cooling Water System, Fuel Oil Chemistry, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Lubricating Oil Analysis programs to address loss of coating integrity, as amended by letters dated January 13, 2014, May 5, 2014, June 30, 2014, and August 29, 2014, the staff determines that the revised AMPs are adequate to manage the applicable aging effects. The staff concludes that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplements for these AMPs and concludes that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in the Application

In LRA Appendix A: "Updated Final Safety Analysis Report Supplement," Section A.1.5, "Quality Assurance Program and Administrative Controls," and Appendix B: "Aging Management Programs," Section B.1.3, "Quality Assurance Program and Administrative Controls," the applicant described the elements of corrective action, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components.

LRA Appendix A, Section A.1.5, states:

> The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, 'Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)' of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR).

LRA Appendix B, Section B.1.3, states:

> The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, 'Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)' of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to AMR.

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 QA activities of corrective action, confirmation process, and administrative controls. Table A.1-1, "Elements of an Aging Management Program for License Renewal," of Branch Technical Position RLSB-1 provides the following description of these quality attributes:

- Attribute No. 7 - Corrective Actions, including root cause determination and prevention of recurrence, which should be timely
- Attribute No. 8 - Confirmation Process, which should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective

- Attribute No. 9 - Administrative Controls, which should provide a formal review and approval process

The SRP-LR, Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs," states that those aspects of the AMP that affect quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the applicant's existing 10 CFR Part 50, Appendix B, QA program may be used to address the elements of corrective action, confirmation process, and administrative control. Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

> Safety-related SCs are subject to Appendix B to 10 CFR Part 50 requirements which are adequate to address all quality related aspects of an AMP consistent with the CLB of the facility for the period of extended operation. For nonsafety-related SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its Appendix B to 10 CFR Part 50 program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the Final Safety Analysis Report supplement in accordance with 10 CFR 54.21(d).

The staff reviewed LRA Sections Appendix A, Section A.1.5, and Appendix B, Section B.1.3, which describe how the applicant's existing QA program includes the QA-related elements (corrective action, confirmation process, and administrative controls) for AMPs consistent with the staff's guidance described in Branch Technical Position IQMB-1. The staff also reviewed a sample of AMP program basis documents and confirmed that the AMPs implement the CAP, confirmation processes, and administrative controls as described in the LRA. Based on its review, the staff determined that the quality attributes presented in the AMP program basis documents and the associated AMPs are consistent with the staff's position regarding QA for aging management.

3.0.4.3 Conclusion

On the basis of the staff's evaluation of LRA Appendix A, Section A.1.5, and Appendix B, Section B.1.3, and the AMP program basis documents, the staff concludes that the QA attributes (corrective action, confirmation process, and administrative control) of the applicant's AMPs are consistent with SRP-LR, Branch Technical Position RLSB-1.

3.0.5 Operating Experience for Aging Management Programs

3.0.5.1 Summary of Technical Information in Application

LRA Section B.1.4 describes the consideration of OE for AMPs. The LRA states that internal and external OE is captured and systematically reviewed on an ongoing basis using the QA program and the Operating Experience Program. As stated in the LRA, OE is used "to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants." The LRA also states that Byron and Braidwood participates in the Exelon Operating Experience (OPEX) process which provides OE on a daily basis and screens, evaluates, and provides actions to prevent or mitigate the consequences of similar events.

3.0.5.2 Staff Evaluation

3.0.5.2.1 Overview

In accordance with 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 in a way consistent with the CLB for the period of extended operation. SRP-LR Appendix A describes 10 elements of an acceptable AMP. SRP-LR Section A.1.2.3.10 describes program element 10, "operating experience." On March 16, 2012, the staff issued Final LR-ISG-2011-05, "Ongoing Review of Operating Experience." This LR-ISG includes interim revisions to the SRP-LR to clarify criteria for the "operating experience" program element. Specifically, there are three criteria from SRP-LR Section A.1.2.3.10, as revised by LR-ISG-2011-05:

(1) Consideration of future plant-specific and industry operating experience relating to AMPs should be discussed. The ongoing review of operating experience may identify areas where AMPs should be enhanced or new AMPs developed. As such, an applicant should ensure that it has adequate processes to monitor and evaluate plant-specific and industry operating experience related to aging management to ensure that the AMPs are effective in managing the aging effects for which they are credited. The AMPs are informed by this review of operating experience on an ongoing basis, regardless of the AMP's implementation schedule. The ongoing review of operating experience information should provide objective evidence to support the conclusion that the effects of aging are managed adequately so that the [SC] intended function(s) will be maintained during the period of extended operation.

(2) Currently available operating experience with existing programs should be discussed. The operating experience of existing programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has not been fully effective in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the [SC] intended function(s) will be maintained during the period of extended operation.

(3) Currently available operating experience applicable to new programs also should be discussed. For new AMPs that have yet to be implemented at an applicant's facility, the programs have not yet generated any operating experience. However, there may be other relevant plant-specific or generic industry operating experience that is relevant to the program elements, even though the operating experience was not identified through implementation of the new program. Thus, when developing the elements for new programs, an applicant should consider the impact of relevant operating experience from implementation of its existing AMPs and from generic industry operating experience.

SER Section 3.0.3 discusses the staff's review of the second and third criteria, which concern currently available OE associated with existing and new programs, respectively. The following evaluation covers the staff's review of the first criterion, which concerns the consideration of future OE.

3.0.5.2.2 Consideration of Future Operating Experience

The staff reviewed LRA Sections B.1.4 and B.2 to determine how the applicant will use future OE to ensure that the AMPs are effective. Each of the program descriptions in LRA Section B.2 indicate that LRA Section B.1.4 describes the process for review of future plant-specific and industry OE. In addition, LRA Section B.2 indicates that all of the applicant's AMPs are consistent with AMPs described in the GALL Report. By issuance of LR-ISG-2011-05, the staff revised the "operating experience" program elements for all of the GALL Report AMPs. The revised program elements state that each of the AMPs should be informed and enhanced when necessary through programmatic OE review activities that are consistent with guidelines in GALL Report Appendix B (a new appendix also established in LR-ISG-2011-05). Based on its review, the staff determined that LRA Section B.1.4 provides a general description of the applicant's programmatic activities for review of future plant-specific and industry OE; however, the LRA does not contain sufficient information to demonstrate that certain activities are consistent with the new GALL Report Appendix B. By letter dated March 11, 2014, the staff issued RAI B.1.4-1 requesting that the applicant provide additional information on its ongoing OE review activities to support their consistency with the areas described in LRA Section B.2, which indicates that all the applicant's AMPs are consistent with the GALL Report.

By letter dated April 8, 2014, the applicant responded to RAI B.1.4-1 with additional information on its programmatic activities for the ongoing review of OE, specifically information regarding training and the evaluation of AMP implementation results.

SRP-LR Section A.4, which was established in LR-ISG-2011-05 and is consistent with GALL Report Appendix B, provides a framework for activities acceptable to the staff for the ongoing review of OE concerning age-related degradation and aging management to ensure the effectiveness of AMPs and activities. The staff evaluated the applicant's OE review activities, as described in the LRA and its response to RAI B.1.4-1, against the guidance in SRP-LR Section A.4.2 on "Acceptable Use of Existing Programs" and "Areas of Further Review." The staff's evaluations with respect to these SRP-LR sections follow in SER Sections 3.0.5.2.3 and 3.0.5.2.4, respectively.

3.0.5.2.3 Acceptability of Existing Programs

SRP-LR Section A.4.2 describes existing programs generally acceptable to the staff for the capture, processing, and evaluation of OE concerning age-related degradation and aging management during the term of a renewed operating license. The acceptable programs are those relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and NUREG-0737, item I.C.5. SRP-LR Section A.4.2 also states that, as part of meeting the requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.D, "Procedures for Feedback of Operating Experience to Plant Staff," item I.C.5, the applicant's Operating Experience Program should rely on active participation in the INPO OE program (formerly the INPO Significant Event Evaluation and Information Network program endorsed in NRC GL 82-04, "Use of INPO SEE-IN Program," dated March 9, 1982).

LRA Section B.1.4 states that the applicant uses its QA program and Operating Experience Program to systematically capture and review OE from internal and external sources. The applicant stated that the QA program meets the requirements of 10 CFR Part 50 Appendix B, and the Operating Experience Program meets the requirements of NUREG-0737. The applicant further stated that the Operating Experience Program interfaces and relies on active participation in the INPO OE program. Based on this information, the staff determined that the applicant's QA Program and Operating Experience Program are consistent with the programs described in SRP-LR Section A.4.2.

3.0.5.2.4 Areas of Further Review

Application of Existing Programs and Procedures to the Processing of Operating Experience Related to Aging. SRP-LR Section A.4.2 states that the programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and NUREG-0737, item I.C.5, should not preclude the consideration of OE on age-related degradation and aging management. The applicant stated that internal and external OE is systematically captured and reviewed by the QA program, which is consistent with 10 CFR Part 50 Appendix B, and the Operating Experience Program, which is consistent with NUREG-0737, item I.C.5. LRA Section B.1.4 states that the ongoing evaluation of OE includes aging management. In addition, the LRA states that the Operating Experience Program will be enhanced to provide specific direction to identify and evaluated OE related to aging. Based on this information, the staff determined that the processes implemented under the QA program, the CAP, and the enhanced Operating Experience Program would not preclude consideration of age-related OE, which is consistent with the guidance in SRP-LR Section A.4.2. Also, SRP-LR Section A.4.2 states that the applicant should use the option described in SRP-LR Appendix A.2 to expand the scope of 10 CFR Part 50, Appendix B, program to include nonsafety-related SCs. LRA Section B.1.3 states that the applicant's QA Program includes nonsafety-related SCs, which the staff finds consistent with the guidance in SRP-LR Section A.2, and therefore consistent with SRP-LR A.4.2 as well. SER Section 3.0.4 documents the staff's evaluation of LRA Section B.1.3.

Consideration of Guidance Documents as Industry Operating Experience. SRP-LR Section A.4.2 states that NRC and industry guidance documents and standards applicable to aging management, including revisions to the GALL Report, should be considered as sources of industry OE and evaluated accordingly. LRA Section B.1.4 states that the sources of external OE include INPO documents, the Exelon OPEX process, NRC documents, and other documents, such as Licensee Event Reports and 10 CFR Part 21 Reports. The applicant also stated that the Operating Experience Program will be enhanced to require the review of industry OE sources for aging-related degradation or impacts to aging management activities. The applicant also listed additional external sources which include LR-ISGs and GALL Report revisions. The staff finds the sources of industry OE acceptable because the applicant will consider an appropriate breadth of industry OE for impacts to its aging management activities, which includes sources that the staff considers to be the primary sources of external OE information. The applicant's consideration of industry guidance documents as OE is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Screening of Incoming Operating Experience. SRP-LR Section A.4.2 states that all incoming plant-specific and industry OE should be screened to determine whether it involves age-related degradation or impacts to aging management activities. LRA Section B.1.4 states that internal and external OE is captured and systematically reviewed on an ongoing basis. The applicant stated that the Operating Experience Program will be enhanced to establish criteria to define aging-related degradation and to require the review of internal and external OE for age-related degradation or impacts to aging management activities. The staff finds the applicant's OE review processes acceptable because, after enhancement, these processes will include screening of all new OE to identify and evaluate items that have the potential to impact the aging management activities. The applicant's screening of plant-specific and industry OE is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Identification of Operating Experience Related to Aging. SRP-LR Section A.4.2 states that coding should be used within the plant CAP to identify OE involving age-related degradation applicable to the plant. The SRP-LR also states that the associated entries should be periodically reviewed and any adverse trends should receive further evaluation. LRA Section B.1.4 states that the Operating Experience Program will be enhanced to establish identification codes with definitions within the CAP for use in identification, trending, and communication of age-related degradation. The enhanced Operating Experience Program will also require station personnel to periodically assess the performance of the AMPs, including insights obtained through OE. The applicant stated that adverse trends will be entered into the CAP for evaluation, which will also evaluate the need for AMP revisions or new AMPs, as appropriate. The staff finds the applicant's identification of OE related to aging acceptable because the applicant has a means at a programmatic level to identify, trend, and evaluate OE that involves age-related degradation. The applicant's identification of age-related OE applicable to the plants is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Information Considered in Operating Experience Evaluations. SRP-LR Section A.4.2 states that OE identified as involving aging should receive further evaluation based on consideration of information such as the affected SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. The SRP-LR also states that actions should be initiated within the CAP to either enhance the AMPs or develop and implement new AMPs if it is found through an OE evaluation that the effects of aging may not be adequately managed. LRA Section B.1.4 states that the ongoing evaluation of OE related to aging management will consider plant SSCs, material of construction, operating environment, associated aging effects, associated aging mechanisms, associated AMPs, as well as the activities, criteria, and evaluations integral to the elements of the plant AMPs. The applicant further stated that if the AMPs are determined to be ineffective, then they will be evaluated to determine if AMP changes are appropriate or new AMPs are needed. The applicant stated that the Operating Experience Program and the CAP will be utilized to determine the effectiveness of programs that address age-related degradation. The staff determined that the applicant's evaluations of age-related OE will include the assessment of appropriate information to determine potential impacts to the aging management activities. The staff also determined that the applicant's Operating Experience Program, in conjunction with the CAP, will implement any changes necessary to manage the effects of aging, as determined through its OE evaluations. Therefore, the staff finds that the information considered in the applicant's OE evaluations and use of the Operating Experience Program and CAP to ensure that the effects of aging are adequately managed is consistent with the guidance in SRP-LR Section A.4.2.

Evaluation of AMP Implementation Results. SRP-LR Section A.4.2 states that the results of implementing the AMPs, such as data from inspections, tests, and analyses, should be evaluated regardless of whether the acceptance criteria of the particular AMP have been met. SRP-LR Section A.4.2 states that this information should be used to determine whether it is necessary to adjust the inspection activities for aging management. In addition, SRP-LR Section A.4.2 states that actions should be initiated within the plant CAP to either enhance the AMPs or develop and implement new AMPs if these evaluations indicate that the effects of aging may not be adequately managed. LRA Section B.1.4 states that the Operating Experience Program will be enhanced to require station personnel to periodically assess the performance of the AMPs, including insights obtained through OE. The applicant stated that adverse trends will be entered into the CAP for evaluation, which will also evaluate the need for AMP revisions or new AMPs, as appropriate. In its response to RAI B.1.4-1, the applicant provided further details on how the review of internal and external OE will be used to evaluate AMPs. The applicant stated that it will review internal OE, including completed work activities associated with implementing the license renewal commitments to determine whether AMP revisions or new AMPs are needed. The applicant also clarified that the periodic assessments of AMP performance will be performed regardless of whether AMP acceptance criteria are met. The staff reviewed the LRA and the response to RAI B.1.4-1 and finds the applicant's treatment of AMP implementation results as OE acceptable because the applicant will evaluate these results and use the information to determine whether to adjust the aging management activities. The applicant's activities for the evaluation of AMP implementation results are, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Training. SRP-LR Section A.4.2 states that training on age-related degradation and aging management should be provided to those personnel responsible for implementing the AMPs and those personnel that may submit, screen, assign, evaluate, or otherwise process plant-specific and industry OE. SRP-LR Section A.4.2 also states that the training should be periodic and include provisions to accommodate the turnover of plant personnel. LRA Section B.1.4 states that the Operating Experience Program will be enhanced to provide training to those personnel responsible for screening, evaluating, and communicating OE items related to aging management and age-related degradation, commensurate with each person's role in the process. The applicant stated that the training will be provided periodically and include provisions to accommodate personnel turnover. In its response to RAI B.1.4-1, the applicant provided examples of topics related to aging management and aging-related degradation that will be included in its training program for engineering and maintenance personnel. For example, the applicant stated that the training will include topics on key license renewal topics, age-related degradation mechanisms and indicators for various materials, and aging assessment process terms. The applicant stated that other personnel will be trained on how to recognize "potential aging issues" and communicate them to appropriate site subject matter experts, who will determine if the issues need to be entered into the CAP. The staff reviewed the LRA and the response to RAI B.1.4-1 and determined that the scope of personnel included in the applicant's training program, along with the provisions for recurring training and accounting for personnel turnover, are consistent with the guidelines in SRP-LR A.4.2. The staff also determined that the applicant demonstrated that its training program, when enhanced, will cover age-related degradation and aging management topics. The applicant's enhanced training activities are, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Reporting Operating Experience to the Industry. SRP-LR Section A.4.2 states that guidelines should be established for reporting plant-specific OE on age-related degradation and aging management to the industry. LRA Section B.1.4 states that Byron and Braidwood participates in the Exelon OPEX process and the INPO OE program. The applicant stated that the Operating Experience Program will be enhanced to require communication of significant internal age-related degradation, associated with SSCs within the scope of license renewal, to other Exelon plants and to the industry. The applicant also stated that it will establish criteria for determining when age-related degradation is significant. The staff finds this acceptable because, after the enhancement, the applicant will have established appropriate expectations and guidelines for identifying and communicating significant plant-specific OE concerning aging management and age-related degradation to the industry. The applicant's establishment of these guidelines is, therefore, consistent with the guidance in SRP-LR A.4.2.

Schedule for Implementing the Operating Experience Review Activities. SRP-LR Section A.4.2 states that any enhancements to existing OE review activities should be put in place no later than the date when the renewed operating license is issued. LRA Section B.1.4 identifies several enhancements to the Operating Experience Program. The applicant stated that these enhancements will be implemented no later than the date that the renewed operating licenses are issued, which the staff finds acceptable.

SRP-LR Section A.4.2 also states that the OE review activities should be implemented on an ongoing basis throughout the term of a renewed license. LRA Section B.1.4 states that the enhanced Operating Experience Program will be implemented on an ongoing basis throughout the terms of the renewed licenses. In addition, LRA Section A.1.6 provides the UFSAR supplement summary description of the applicant's enhanced programmatic activities for ongoing review of the OE. On issuance of the renewed licenses in accordance with 10 CFR 54.3(c), this summary description will be incorporated into each plant's CLB and, at that time, the applicant will be obligated to conduct its OE review activities accordingly. The staff finds the implementation schedule acceptable because the applicant will implement the enhanced OE review activities on an ongoing basis throughout the term of the renewed operating licenses. This ongoing implementation is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

3.0.5.2.5 Summary

Based on its review of the LRA and the applicant's response to RAI B.1.4-1, the staff determined that the applicant's programmatic activities for the ongoing review of OE are consistent with the guidance in SRP-LR Section A.4.2, as established in LR-ISG-2011-05. These activities are therefore acceptable for: (a) the systematic review of plant-specific and industry OE to ensure that the license renewal AMPs are and will continue to be effective in managing the aging effects for which they are credited and (b) the enhancement of AMPs or development of new AMPs when it is determined through the evaluation of OE that the effects of aging may not be adequately managed. Based on the completion of the staff's review and the consistency of the applicant's OE review activities with the guidance in LR-ISG-2011-05, the staff's concerns described in RAI B.1.4-1 are resolved.

3.0.5.3 UFSAR Supplement

In accordance with 10 CFR 54.21(d), the UFSAR supplement must contain a summary description of the programs and activities for managing the effects of aging. LRA Section A.1.6 provides the UFSAR supplement summary description of the applicant's programmatic activities for the ongoing review of OE. It also identifies enhancements that will be implemented to ensure that plant-specific and industry OE related to aging management will be used effectively.

The staff reviewed LRA Section A.1.6 and found that, whereas LRA Section B.1.4 states that the ongoing evaluation of OE related to aging management will consider: (a) SSCs, (b) materials, (c) environments, (d) aging effects, (e) aging mechanisms, (f) AMPs, and (g) activities, criteria, and evaluations integral to the elements of the AMPs, the summary description in LRA Section A.1.6 does not reflect that the evaluation will consider this information.

By letter dated March 11, 2014, the staff issued RAI B.1.4-2, requesting that the applicant revise LRA Section A.1.6 to reflect the specific information that is considered in the ongoing evaluation of OE related to aging management, as stated in LRA Section B.1.4. Alternatively, the staff requested the applicant to provide a justification for not including this information in the UFSAR supplement. By letter dated April 8, 2014, the applicant responded to RAI B.1.4-2. The applicant revised LRA Section A.1.6 to reflect the specific information that is considered in the ongoing evaluations of OE related to aging management, consistent with LRA Section B.1.4.

SRP-LR Section A.4.2, as established in LR-ISG-2011-05, states that the programmatic activities for the ongoing review of plant-specific and industry OE concerning age-related degradation and aging management should be described in the UFSAR supplement. LR-ISG-2011-05 also revises SRP-LR Table 3.0-1 to include example summary description language for the UFSAR supplement. The staff reviewed the content of LRA Section A.1.6, as amended by letter dated April 8, 2014, against the example language in SRP-LR Table 3.0-1. Based on its review, the staff determined that the content of the applicant's summary description is consistent with the example and is also sufficiently comprehensive to describe the applicant's programmatic activities for evaluating OE to maintain the effectiveness of the AMPs. Therefore, the staff finds the applicant's UFSAR supplement summary description acceptable. The staff's concern described in RAI B.1.4-2 is resolved.

3.0.5.4 Conclusion

Based on its review of the applicant's programmatic activities for the ongoing review of OE, including the response to RAI B.1.4-1, the staff concludes that the applicant demonstrated that OE will be reviewed to ensure that the effects of aging will be adequately managed so that the intended functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for these activities and concludes that it provides an adequate summary description, as required by 10 CFR 54.21(d).

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

This section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, RVIs, and RCS components and component groups of the following:

- RCS
- Reactor Vessel
- Reactor Vessel Internals
- Steam Generators

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the reactor vessel, RVIs, and RCS components and components groups. LRA Table 3.1.1, "Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the reactor vessel, RVIs, and RCS components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry OE 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 OE included a review of the GALL Report and OE issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

Table 3.1-1 Staff Evaluation for Reactor Vessel, Internals, and Reactor Coolant System Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High strength, low-alloy steel top head closure stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-1)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP-LR, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Nickel alloy tubes and sleeves exposed to reactor coolant and secondary feedwater/steam (3.1.1-2)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP-LR, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Stainless steel or nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-3)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP-LR, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel pressure vessel support skirt and attachment welds (3.1.1-4)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, or steel (with stainless steel or nickel-alloy cladding) steam generator components, pressurizer relief tank components or piping components or bolting (3.1.1-5)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP-LR, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), or stainless steel; or nickel alloy reactor coolant pressure boundary components: piping, piping components, and piping elements exposed to reactor coolant (3.1.1-6)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (See SRP-LR, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), or stainless steel; or nickel alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant (3.1.1-7)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP-LR, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without nickel-alloy or stainless steel cladding), or stainless steel; or nickel alloy steam generator components exposed to reactor coolant (3.1.1-8)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP-LR, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), stainless steel; nickel alloy RCPB piping; flanges; nozzles & safe ends; pressurizer shell heads & welds; heater sheaths & sleeves; penetrations; thermal sleeves exposed to reactor coolant (3.1.1-9)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP-LR, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), stainless steel; nickel alloy reactor vessel flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant (3.1.1-10)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP-LR, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles (3.1.1-11)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA evaluated for the period of extended operation; check ASME Code limits for allowable cycles (less than 7,000 cycles) of thermal stress range (see SRP-LR Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2)
Steel steam generator components: upper and lower shells, transition cone; new transition cone closure weld exposed to secondary feedwater or steam (3.1.1-12)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry," and, for Westinghouse Model 44 and 51 S/G, if corrosion of the shell is found, additional inspection procedures are developed	Yes	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report (see SER Section 3.1.2.2.2(1) and 3.1.2.2.2(2))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux (3.1.1-13)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA is to be evaluated in accordance with Appendix G of 10 CFR Part 50 and RG 1.99. The applicant may choose to demonstrate that the materials of the nozzles are not controlling for the TLAA evaluations.	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.3(1))
Steel (with or without cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-14)	Loss of fracture toughness due to neutron irradiation embrittlement	Chapter XI.M31, "Reactor Vessel Surveillance"	Yes	Reactor Vessel Surveillance program	Consistent with the GALL Report (see SER Section 3.1.2.2.3(2))

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-15)	Reduction in ductility and fracture toughness due to neutron irradiation	Ductility - Reduction in Fracture Toughness is a TLAA to be evaluated for the period of extended operation. See the SRP-LR, Section 4.7, "Other Plant-Specific TLAAs," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1).	Yes, TLAA	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.3(3))
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (3.1.1-16)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	A plant-specific aging management program is to be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC in the vessel flange leak detection line	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-17)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry" for BWR water, and a plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(2))

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat input welding process exposed to reactor coolant (3.1.1-18)	Crack growth due to cyclic loading	Growth of intergranular separations is a TLAA evaluated for the period of extended operation. The SRP-LR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis," provides guidance for meeting the requirements of 10 CFR 54.21(c)).	Yes, TLAA	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.5)
Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes (external to reactor vessel) (3.1.1-19)	Cracking due to stress corrosion cracking	A plant-specific aging management program is to be evaluated	Yes	ASME XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report (see SER Section 3.1.2.2.6(1))
Cast austenitic stainless steel Class 1 piping, piping components, and piping elements exposed to reactor coolant (3.1.1-20)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry" and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific aging management program	Yes	ASME XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report (see SER Section 3.1.2.2.6(2))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-21)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components. The ISI program is to be augmented by a plant-specific verification program.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.7)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-22)	Loss of material due to erosion	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.8)
Stainless steel or nickel alloy PWR reactor vessel internal components (inaccessible locations) exposed to reactor coolant and neutron flux (3.1.1-23)	Cracking due to stress corrosion cracking and irradiation-assisted stress-corrosion cracking	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	Yes	PWR Vessel Internals Program and Water Chemistry Program Exceptions apply to PWR Vessel Internals Program	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.9)
Stainless steel or nickel alloy PWR reactor vessel internal components (inaccessible locations) exposed to reactor coolant and neutron flux (3.1.1-24)	Loss of fracture toughness due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to wear	Chapter XI.M16A, "PWR Vessel Internals"	Yes	PWR Vessel Internals Program Exceptions apply to PWR Vessel Internals Program	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.10)
Steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant (3.1.1-25)	Cracking due to primary water stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	Yes	Water Chemistry Program and Steam Generators Program	Consistent with the GALL Report (see SER Sections 3.1.2.2.11(1) and 3.1.2.2.11(2))

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel Combustion Engineering core support barrel assembly: lower flange weld exposed to reactor coolant and neutron flux. Upper internals assembly: fuel alignment plate (applicable to plants with core shrouds assembled with full height shroud plates) exposed to reactor coolant and neutron flux. Lower support structure: core support plate (applicable to plants with a core support plate) exposed to reactor coolant and neutron flux (3.1.1-26)	Cracking due to fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry," if fatigue life cannot be confirmed by TLAA	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.12)
Nickel alloy Westinghouse control rod guide tube assemblies, guide tube support pins exposed to reactor coolant and neutron flux (3.1.1-27)	Cracking due to stress corrosion cracking and fatigue	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.13)
Nickel alloy Westinghouse control rod guide tube assemblies, guide tube support pins, and Zircaloy-4 Combustion Engineering incore instrumentation thimble tubes exposed to reactor coolant and neutron flux (3.1.1-28)	Loss of material due to wear	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.1.2.2.14)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant (3.1.1-29)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and Chapter XI.M2, “Water Chemistry,” and for BWRs with a crevice in the access hole covers, augmented inspection using UT or other acceptable techniques	No	Not applicable	Not applicable to PWRs
Stainless steel or nickel alloy penetration: drain line exposed to reactor coolant (3.1.1-30)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, cyclic loading	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-31)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure, exposed to reactor coolant and neutron flux (3.1.1-32)	Cracking, or loss of material due to wear	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Stainless steel, steel with stainless steel cladding Class 1 reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-33)	Cracking due to stress corrosion cracking	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD” for ASME components, and Chapter XI.M2, “Water Chemistry”	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60 °C (>140 °F) (3.1.1-34)	Cracking due to stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for ASME components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-35)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Steel, stainless steel pressurizer integral support exposed to air with metal temperature up to 288 °C (550 °F) (3.1.1-36)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Steel reactor vessel flange (3.1.1-37)	Loss of material due to wear	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Cast austenitic stainless steel Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F) (3.1.1-38)	Loss of fracture toughness due to thermal aging embrittlement	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components. For pump casings and valve bodies, screening for susceptibility to thermal aging is not necessary.	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, or steel with stainless steel cladding Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant (3.1.1-39)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking (for stainless steel only), and thermal, mechanical, and vibratory loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, Chapter XI.M2, "Water Chemistry," and XI.M35, "One-Time Inspection of ASME Code Class 1 Small-bore Piping"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; One-Time Inspection of ASME Code Class 1 Small Bore-Piping Program; and Water Chemistry Program	Consistent with the GALL Report
Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-40)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report
Nickel alloy core support pads; core guide lugs exposed to reactor coolant (3.1.1-40x)	Cracking due to primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report
Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant (3.1.1-41)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel with stainless steel or nickel alloy cladding or stainless steel primary side components; steam generator upper and lower heads, and tube sheet weld; or pressurizer components exposed to reactor coolant (3.1.1-42)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD” for Class 1 components, and Chapter XI.M2, “Water Chemistry”	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel and nickel-alloy reactor vessel internals exposed to reactor coolant (3.1.1-43)	Loss of material due to pitting and crevice corrosion	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD” for Class 1 components, and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam (3.1.1-44)	Loss of material due to erosion	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD” for Class 2 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Nickel alloy and steel with nickel-alloy cladding reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-45)	Cracking due to primary water stress corrosion cracking	Chapter XI.M1, “ASME Section XI ISI, IWB, IWC & IWD,” and Chapter XI.M2, “Water Chemistry,” and, for nickel-alloy, Chapter XI.M11B, “Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)”	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program; and Water Chemistry Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel-alloy, nickel-alloy welds and/or buttering control rod drive head penetration pressure housing or nozzles safe ends and welds (inlet, outlet, safety injection) exposed to reactor coolant (3.1.1-46)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry," and, for nickel-alloy, Chapter XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program; and Water Chemistry Program	Consistent with the GALL Report
Stainless steel, nickel-alloy control rod drive head penetration pressure housing exposed to reactor coolant (3.1.1-47)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report
Steel external surfaces: reactor vessel top head, reactor vessel bottom head, reactor coolant pressure boundary piping or components adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage (3.1.1-48)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion," and Chapter XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)"	No	Boric Acid Corrosion Program and Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program	Consistent with the GALL Report
Steel reactor coolant pressure boundary external surfaces or closure bolting exposed to air with borated water leakage (3.1.1-49)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cast austenitic stainless steel Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant >250 °C (>482 °F) (3.1.1-50)	Loss of fracture toughness due to thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program	Consistent with the GALL Report
Stainless steel or nickel-alloy Babcock & Wilcox reactor internal components exposed to reactor coolant and neutron flux (3.1.1-51)	Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable. Babcock and Wilcox PWR Only.	Not applicable to Byron and Braidwood
Stainless steel or nickel-alloy Combustion Engineering reactor internal components exposed to reactor coolant and neutron flux (3.1.1-52)	Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable. Combustion Engineering PWR Only.	Not applicable to Byron and Braidwood
Stainless steel or nickel-alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-53)	Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	PWR Vessel Internals Program and Water Chemistry Program Exceptions apply to PWR Vessel Internals Program	Consistent with the GALL Report
Stainless steel bottom mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux (3.1.1-54)	Loss of material due to wear	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M37, "Flux Thimble Tube Inspection"	No	Flux Thimble Tube Inspection Program and PWR Vessel Internals Program Exceptions apply to PWR Vessel Internals Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel thermal shield assembly, thermal shield flexures exposed to reactor coolant and neutron flux (3.1.1-55)	Cracking due to fatigue; Loss of material due to wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel or nickel-alloy Combustion Engineering reactor internal components exposed to reactor coolant and neutron flux (3.1.1-56)	Loss of fracture toughness due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable. Combustion Engineering PWR Only.	Not applicable to Byron and Braidwood
Stainless steel or nickel-alloy Babcock & Wilcox reactor internal components exposed to reactor coolant and neutron flux (3.1.1-58)	Loss of fracture toughness due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable. Babcock & Wilcox PWR Only.	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel-alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-59)	Loss of fracture toughness due to neutron irradiation embrittlement; or changes in dimension due to void swelling; or loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to wear	Chapter XI.M16A, “PWR Vessel Internals”	No	PWR Vessel Internals Program Exceptions apply to PWR Vessel Internals Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-60)	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Not applicable	Not applicable to PWRs
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-61)	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Flow-Accelerated Corrosion Program	Consistent with the GALL Report
High-strength, low alloy steel, or stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-62)	Cracking due to stress corrosion cracking	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity Program	Consistent with the GALL Report
Steel or stainless steel closure bolting exposed to air with reactor coolant leakage (3.1.1-63)	Loss of material due to general (steel only), pitting, and crevice corrosion or wear	Chapter XI.M18, “Bolting Integrity”	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel closure bolting exposed to air – indoor uncontrolled (3.1.1-64)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity Program	Consistent with the GALL Report
Stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-65)	Loss of material due to wear	Chapter XI.M18, “Bolting Integrity”	No	Not applicable	Not applicable to Byron and Braidwood
High-strength, low alloy steel, or stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-66)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity Program	Consistent with the GALL Report
Steel or stainless steel closure bolting exposed to air – indoor with potential for reactor coolant leakage (3.1.1-67)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity Program	Consistent with the GALL Report
Nickel alloy steam generator tubes exposed to secondary feedwater or steam (3.1.1-68)	Changes in dimension (“denting”) due to corrosion of carbon steel tube support plate	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable.	Not applicable to Byron and Braidwood
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam (3.1.1-69)	Cracking due to outer diameter stress corrosion cracking and intergranular attack	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators Program and Water Chemistry Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-70)	Cracking due to primary water stress corrosion cracking	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators Program and Water Chemistry Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report
Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam (3.1.1-71)	Cracking due to stress corrosion cracking or other mechanism(s); loss of material due general (steel only), pitting, and crevice corrosion	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators Program and Water Chemistry Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report
Steel steam generator tube support plate, tube bundle wrapper, supports, and mounting hardware exposed to secondary feedwater or steam (3.1.1-72)	Loss of material due to erosion, general, pitting, and crevice corrosion, ligament cracking due to corrosion	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators Program and Water Chemistry Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report
Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam (3.1.1-73)	Loss of material due to wastage and pitting corrosion	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to Byron and Braidwood
Steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam (3.1.1-74)	Wall thinning due to flow-accelerated corrosion	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators Program and Water Chemistry Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator tube support lattice bars exposed to secondary feedwater or steam (3.1.1-75)	Wall thinning due to flow-accelerated corrosion and general corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Byron and Braidwood
Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam (3.1.1-76)	Loss of material due to fretting	Chapter XI.M19, "Steam Generators"	No	Steam Generators Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam (3.1.1-77)	Loss of material due to wear and fretting	Chapter XI.M19, "Steam Generators"	No	Steam Generators Program Exceptions apply to Steam Generators Program	Consistent with the GALL Report
Nickel alloy steam generator components such as secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam (3.1.1-78)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection," or Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-79)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (non-ASME Section XI components) exposed to treated borated water >60 °C (>140 °F) (3.1.1-80)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel pressurizer spray head exposed to reactor coolant (3.1.1-81)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Nickel alloy pressurizer spray head exposed to reactor coolant (3.1.1-82)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood
Steel steam generator shell assembly exposed to secondary feedwater or steam (3.1.1-83)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (3.1.1-84)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant (3.1.1-85)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs
Stainless steel steam generator primary side divider plate exposed to reactor coolant (3.1.1-86)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel or nickel-alloy PWR reactor internal components exposed to reactor coolant and neutron flux (3.1.1-87)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry Program	Consistent with the GALL Report
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-88)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-89)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-90)	Loss of material due to pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength low alloy steel closure head stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-91)	Cracking due to stress corrosion cracking; loss of material due to general, pitting, and crevice corrosion, or wear (BWR)	Chapter XI.M3, “Reactor Head Closure Stud Bolting”	No	Not applicable	Not applicable to PWRs
High-strength low alloy steel closure head stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-92)	Cracking due to stress corrosion cracking; loss of material due to general, pitting, and crevice corrosion, or wear (PWR)	Chapter XI.M3, “Reactor Head Closure Stud Bolting”	No	Reactor Head Closure Stud Bolting Program	Consistent with the GALL Report
Copper alloy >15% Zn or > 8% Al piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-93)	Loss of material due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-94)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M4, “BWR Vessel ID Attachment Welds,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-95)	Cracking due to cyclic loading	Chapter XI.M5, “BWR Feedwater Nozzle”	No	Not applicable	Not applicable to PWRs
Steel (with or without stainless steel cladding) control rod drive return line nozzles exposed to reactor coolant (3.1.1-96)	Cracking due to cyclic loading	Chapter XI.M6, “BWR Control Rod Drive Return Line Nozzle”	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS; nozzle safe ends and associated welds (3.1.1-97)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M7, “BWR Stress Corrosion Cracking,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Stainless steel or nickel alloy penetrations: instrumentation and standby liquid control exposed to reactor coolant (3.1.1-98)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, cyclic loading	Chapter XI.M8, “BWR Penetrations,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Cast austenitic stainless steel; PH martensitic stainless steel; martensitic stainless steel; X-750 alloy reactor internal components exposed to reactor coolant and neutron flux (3.1.1-99)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Chapter XI.M9, “BWR Vessel Internals”	No	Not applicable	Not applicable to PWRs
Stainless steel reactor vessel internals components (jet pump wedge surface) exposed to reactor coolant (3.1.1-100)	Loss of material due to wear	Chapter XI.M9, “BWR Vessel Internals”	No	Not applicable	Not applicable to PWRs
Stainless steel steam dryers exposed to reactor coolant (3.1.1-101)	Cracking due to flow-induced vibration	Chapter XI.M9, “BWR Vessel Internals” for steam dryer	No	Not applicable	Not applicable to PWRs
Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant (3.1.1-102)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M9, “BWR Vessel Internals,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor internal components exposed to reactor coolant and neutron flux (3.1.1-103)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs
X-750 alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-104)	Cracking due to intergranular stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals" for core plate, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs
Steel piping, piping components, and piping element exposed to concrete (3.1.1-105)	None	None, provided (1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557, and (2) plant OE indicates no degradation of the concrete	No, if conditions are met	Not applicable	Not applicable to Byron and Braidwood
Nickel alloy piping, piping components, and piping element exposed to air – indoor, uncontrolled, or air with borated water leakage (3.1.1-106)	None	None	NA	Consistent with GALL Report	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping element exposed to gas, concrete, air with borated water leakage, air – indoors, uncontrolled (3.1.1-107)	None	None	NA	Consistent with GALL Report	Consistent with the GALL Report

The staff's review of the reactor vessel, RVIs, and 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 reactor vessel, RVIs, and RCS components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the RCS, RVIs, and RCS components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- Compressed Air Monitoring
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small Bore Piping

- PWR Vessel Internals
- Reactor Head Closure Stud Bolting
- Reactor Vessel Surveillance
- Steam Generators
- TLAA
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)
- Water Chemistry

LRA Tables 3.1.2-1 through 3.1.2-4 summarize the results of AMRs for the reactor vessel, RVIs, and RCS 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 if 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 item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A–E, which indicate how the AMR was consistent with the GALL Report.

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

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff reviewed these AMR items to confirm consistency with the GALL Report and to ensure that the applicant 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 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 AMR items to confirm consistency with the GALL Report. The staff also determined whether the AMR 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 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 AMR items to confirm consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviewed these items to confirm 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 confirm 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.

3.1.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.1.1, items 3.1.1-29 through 3.1.1-31, 3.1.1-41, 3.1.1-43, 3.1.1-60, 3.1.1-63, 3.1.1-79, 3.1.1-84, 3.1.1-85, 3.1.1-91, and 3.1.1-94 through 3.1.1-104, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to boiling-water reactors (BWRs). The staff reviewed the SRP-LR, confirmed these items only apply to BWRs, and finds that these items are not applicable to BBS, which are PWRs.

For LRA Table 3.1.1, items 3.1.1-51, 3.1.1-52, 3.1.1-56, 3.1.1-58, 3.1.1-65, 3.1.1-68, 3.1.1-73, 3.1.1-75, 3.1.1-82, 3.1.1-86, 3.1.1-93, and 3.1.1-105, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at BBS. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.1.1, items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff nonapplicability verification of these items required the review of sources beyond the LRA and UFSAR, and/or the issuance of RAIs.

LRA Table 3.1.1, item 3.1.1-4, addresses the steel pressure vessel support skirt and attachment welds. The GALL Report recommends managing cumulative fatigue damage as a TLAA. The applicant stated that the AMR item is not applicable because it has a Westinghouse reactor vessel that does not have support skirts. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for this item.

LRA Table 3.1.1, item 3.1.1-55, addresses SS thermal shield assembly, thermal shield flexures exposed to reactor coolant and neutron flux. The GALL Report recommends GALL Report AMP XI.M16A, "PWR Vessel Internals," to manage cracking due to fatigue and loss of material due to wear for this component group. The applicant stated that this item is not applicable because there are no SS thermal shield assemblies or thermal shield flexures exposed to reactor coolant and neutron flux in the Reactor Vessel, Internals, and RCS and because Byron and Braidwood RVIs utilize neutron pads that are bolted to the core barrel. The staff evaluated the applicant's claim and finds it acceptable because the UFSAR reflects and confirms the applicant's justification.

3.1.2.1.2 Cracking Due to Primary Water Stress Corrosion Cracking

The LRA Table 3.1.1, item 3.1.1-25, addresses steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant, which will be managed for cracking due to PWSCC. For the AMR items that cite generic note E, the LRA credits the Steam Generators Program to manage the aging effect for steam generator primary side divider plate and steam generator tube-to-tubesheet welds. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that this aging effect is adequately managed.

GALL Report AMP XI.M2 recommends monitoring and controlling the chemical environments of systems and components exposed to reactor coolant, steam, treated borated water, and treated water, such that aging effects of system components are minimized.

The staff's evaluation of the applicant's Water Chemistry and Steam Generators programs is documented in SER Sections 3.0.3.1.1 and 3.0.3.2.5, respectively. The staff noticed that the Water Chemistry Program proposes to manage the effects of aging for steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds by monitoring and controlling system and component chemical environments. The Steam Generators program proposes to take one of the following three options to disposition PWSCC of the divider plate welds: (1) perform a one-time inspection capable of detecting cracks and assess the condition, (2) perform an analytical evaluation which concludes that the RCS pressure boundary will be maintained with divider plate weld cracking, or (3) evaluate results of industry and NRC studies that document that this aging effect is not a credible concern. The Steam Generators Program also proposes to manage PWSCC of the tube-to-tube sheet welds exposed to reactor coolant by performing one of the following three options: (1) perform a one-time inspection capable of detecting cracks to resolve the condition, (2) perform an analytical evaluation to determine that the welds are not susceptible to PWSCC, or (3) perform an analytical evaluation of the welds redefining the RCS pressure boundary of the tubes; thereby, excluding the welds from performing an RCS pressure boundary function. The analytical evaluations performed by the applicant will be submitted to the staff for review and approval prior to entering the period of extended operation. In its response dated March 4, 2014, the applicant stated that if options 2 (PWSCC of the divider plate and tube-to-tubesheet welds) or 3 (PWSCC of the tube-to-tubesheet weld) are taken it will provide the analysis 2 years prior to the period of extended operation.

Based on its review of components associated with item 3.1.1-25 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage the effects of aging using the Steam Generators Program acceptable because by performing one of the above three options, the applicant will be able to manage PWSCC of steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant.

3.1.2.1.3 Stress Corrosion Cracking, Irradiation-Assisted Stress Corrosion Cracking, Fatigue, and Loss of Fracture Toughness

LRA Table 3.1.1, item 3.1.1-53, addresses SS or nickel-alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux, which will be managed for cracking due to SCC, IASCC, or fatigue. The GALL Report, as updated by final LR-ISG-2011-04, recommends GALL Report AMP XI.M16A, PWR Vessel Internals, and GALL Report AMP XI.M2, Water Chemistry, to ensure that this aging effect is adequately managed.

LRA Table 3.1.1, item 3.1.1-59, addresses SS (including CASS, PH SS, or martensitic SS) Westinghouse reactor internal components exposed to reactor coolant and neutron flux, which will be managed for loss of fracture toughness, changes in dimension, loss of preload, and loss of material. The GALL Report, as updated by final LR-ISG-2011-04, recommends GALL Report AMP XI.M16A, PWR Vessel Internals, to ensure that this aging effect is adequately managed.

During its review of components associated with item numbers 3.1.1-53 and 3.1.1-59 for which the applicant cited generic note D, the staff noticed that LRA Table 3.1.2-3 indicates that the core barrel assembly (barrel plates and nozzles) will be managed by the PWR Vessel Internals program for the effects of changes in dimension, cracking, and loss of fracture toughness. The staff noticed that Section 4 of MRP-227-A and LRA Appendix C do not identify the core barrel assembly (barrel plates and nozzles) in the “primary,” “expansion,” or “existing program” inspection categories. The staff also noticed that MRP-191 does not identify the core barrel assembly (barrel plates and nozzles) as a “Category A” component. Since these components are not identified in LRA Appendix C, Section 4 of MRP-227-A or MRP-191, it is unclear how the PWR Vessel Internals Program will be used to manage the effects of changes in dimension, cracking, and loss of fracture toughness in these components.

By letter dated February 18, 2014, the staff issued RAI 3.1.2.3-1 requesting the applicant to explain and justify how the core barrel assembly (barrel plates and nozzles) will be managed for the effects of changes in dimension, cracking, and loss of fracture toughness by the PWR Vessel Internals Program. Specifically, the RAI requested the applicant to address the inspection category, inspection method, frequency, coverage and acceptance criteria, expansion link, and any additional programmatic criteria.

By letter dated March 13, 2014, the applicant responded to RAI 3.1.2.3-1. In its response, the applicant stated that the upper core barrel and lower core barrel, which make up the core barrel assembly, are fabricated from welded plates and are joined by a circumferential weld. The applicant also stated that the upper core barrel includes the outlet nozzles and is welded at the top to the core barrel flange and that the lower core barrel is welded to the core support plate (lower support forging). The applicant stated that the core barrel assembly (barrel plates and nozzles) will be managed for the effects of change in dimension, cracking, and loss of fracture toughness through inspection of the various associated core barrel welds listed in LRA Appendix C, Tables A and B. The applicant stated that these associated core barrel assembly welds include the (1) Core Barrel Assembly: Lower Core Barrel Flange Weld, (2) Core Barrel Assembly: Upper Core Barrel Flange Weld, (3) Core Barrel Assembly: Upper and Lower Core Barrel Cylinder Girth Welds, (4) Core Barrel Assembly: Core Barrel Axial Welds, and (5) Core Barrel Assembly: Core Barrel Outlet Nozzle Welds. The applicant further clarified the examination coverage of these welds includes the adjacent base metal, which includes the core barrel plates and nozzles. The applicant stated that the inspection category, inspection method, frequency, coverage and acceptance criteria, and expansion link are defined in LRA Appendix C for the various associated core barrel welds.

The staff finds the applicant’s response acceptable because the applicant is managing the core barrel assembly (barrel plates and nozzles) through inspection of the core barrel welds described above. The staff confirmed that the noted welds are included in LRA Appendix C and will be managed for the change in dimension, cracking, and loss of fracture toughness. The staff noticed that LRA Appendix C proposes to manage additional aging effects that are not addressed in MRP-227-A. However, the staff finds this acceptable, as documented in the staff's evaluation of PWR Vessel Internals Program in SER Section 3.0.3.2.3. The staff's concern in RAI 3.1.2.3-1 is resolved.

The staff noticed that Table A of LRA Appendix C identifies the Core Barrel Assembly: Upper and Lower Core Barrel Cylinder Girth Welds as being managed for the effects of cracking, loss of fracture toughness, and changes in dimensions as a "primary" inspection category component in the PWR Vessel Internals Program. The staff also noticed that Table B of LRA Appendix C identifies the Lower Internals Assembly: Lower Support Forging as being managed for the effects of cracking, loss of fracture toughness, and changes in dimensions as an "expansion" inspection category component in the PWR Vessel Internals Program. However, the staff noticed that neither of these components was identified by the applicant in its AMR results in LRA Table 3.1.2-3.

By letter dated February 18, 2014, the staff issued RAI 3.1.2.3-2 requesting the applicant to justify the discrepancy between LRA Table 3.1.2-3 and Tables A and B in LRA Appendix C. The staff also requested the applicant to: (a) confirm that all RVIs components are within the scope of license renewal and subject to an AMR and (b) demonstrate that the effects of aging on these components will be adequately managed for the period of extended operation in accordance with 10 CFR 54.21(a)(1) and (a)(3), respectively.

By letter dated March 13, 2014, the applicant responded to RAI 3.1.2.3-2. In its response, the applicant updated LRA Table 3.1.2-3 to include line items for the Core Barrel Assembly: Upper and Lower Core Barrel Cylinder Girth Welds and Lower Internals Assembly: Lower Support Forging to establish consistency between LRA Table 3.1.2-3 and Tables A and B in LRA Appendix C. The applicant reviewed the items listed in LRA Table 3.2.1-3 and determined that all the components classified as "primary," "expansion," and "existing program" and applicable to Byron and Braidwood are accounted for in LRA Table 3.1.2-3, with the exception of the items described above. The applicant further stated that this review determined that not all of the components classified as "no additional measure" and applicable to Byron and Braidwood are accounted for in the AMR. The applicant updated LRA Table 3.1.2-3 to include the AMR of the missing components. The applicant stated that LR-ISG-2011-04 was used as guidance for the line item selection to update LRA Table 3.1.2-3. The applicant stated no changes to the PWR Vessel Internals Inspection Plan provided in LRA Appendix C were required as a result of this review.

The staff finds the applicant's AMR bases, as supplemented by the responses to 3.1.2.3-2, acceptable because the applicant reviewed the RVI components that are within the scope of license renewal and subject to an AMR and updated LRA Table 3.1.2-3 to account for the discrepancies found, which included the Core Barrel Assembly: Upper and Lower Core Barrel Cylinder Girth Welds, Lower Internals Assembly: Lower Support Forging, and "no additional measure" inspection category components. The staff's concern in RAI 3.1.2.3-2 is resolved.

The staff concludes that for LRA items 3.1.1-53 and 3.1.1-59, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

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

LRA Table 3.1.1, item 3.1.1-64, addresses steel bolting exposed to air with borated water leakage, which will be managed for loss of material due to general, pitting, and crevice corrosion. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to ensure that this aging effect is adequately managed for pressure retaining bolting.

During its review of components associated with item number 3.1.1-64 for which the applicant cited generic note A, the staff noticed that LRA Table 3.1.2-2 credits the Bolting Integrity Program to manage the aging effect for structural bolting on the reactor vessel. The staff also noticed that the applicant's Bolting Integrity Program does not manage aging of structural bolting. LRA Section B.2.1.9 states that the Bolting Integrity Program addresses closure bolting on pressure retaining joints and that the aging of structural bolting is managed by either the ASME Section XI, Subsection IWF program, Structures Monitoring program, or the R.G. 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants program. Therefore, by letter dated February 6, 2014, the staff issued RAI 3.1.2-1 requesting that the applicant either revise LRA Section B.2.1.9 to reflect that the Bolting Integrity Program manages the aging of structural bolting or provide an appropriate AMP that manages the identified aging effects for the subject bolting.

In its response dated February 27, 2014, the applicant stated that the subject bolts fasten mechanical elements of the integral reactor vessel head assembly. The applicant also stated that, although the bolts are not closure bolting on pressure retaining joints, the Bolting Integrity Program was determined to be the most appropriate AMP. The application further stated that site walkdown procedures credited by the program include verification of no evidence of corrosion on bolting external surfaces, proper thread engagement, and no evidence of lack of bolting integrity (i.e., loose nuts). The applicant revised LRA Section B.2.1.9 to provide a general description of these parameters monitored.

The staff finds the applicant's response acceptable because the applicant's walkdown activities credited for managing loss of material of the subject bolting are consistent with the staff's recommendations for managing the aging of structural bolting in GALL Report AMP XI.S6, "Structures Monitoring." GALL Report AMP XI.S6 recommends periodic visual inspections (at least every 5 years) of structural bolting to detect loss of material and loose or missing nuts. During its audit of the Bolting Integrity Program, the staff had confirmed that the walkdowns the applicant described were part of the applicant's procedure ER-AA-2030, "Conduct of Plant Engineering Manual," which calls for 100 percent inspection of all components over the course of several walkdowns. The staff's concern described in RAI 3.1.2-1 is resolved.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. As described in the evaluation of RAI 3.1.2-1 above, the Bolting Integrity Program proposes to manage loss of material through periodic visual inspections for evidence of corrosion, which is consistent with the GALL Report guidance for structural bolting. Based on its review of components associated with item 3.1.1-64, for which the applicant cited generic note A, the staff finds the applicant's proposal to manage the effects of aging using the Bolting Integrity Program acceptable because periodic visual inspections, conducted on 100 percent of bolting over the course of several walkdowns, are capable of identifying loss of material of structural bolting prior to loss of intended function.

3.1.2.1.5 Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-Loosening

LRA Table 3.1.1, item 3.1.1-66, addresses steel bolting exposed to air with borated water leakage, which will be managed for loss of preload due to thermal effects, gasket creep, and self-loosening. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to ensure that this aging effect is adequately managed for pressure retaining bolting.

During its review of components associated with item number 3.1.1-66 for which the applicant cited generic note A, the staff noticed that the LRA Table 3.1.2-2 credits the Bolting Integrity Program to manage the aging effect for structural bolting on the reactor vessel. The staff also noticed that the applicant's Bolting Integrity Program does not manage aging of structural bolting. LRA Section B.2.1.9 states that the Bolting Integrity Program addresses closure bolting on pressure retaining joints and that the aging of structural bolting is managed by either the ASME Section XI, Subsection IWF program, Structures Monitoring program, or the R.G. 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants program. The staff's RAI regarding this apparent discrepancy and the evaluation of the applicant's response are documented in SER Section 3.1.2.1.4.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The Bolting Integrity Program proposes to manage the effects of aging for the subject bolting through the use of preventive measures (use of proper torque, checking for uniform gasket compression, and use of proper lubricants) and periodic visual inspections for verification of proper thread engagement and no evidence of lack of bolting integrity (i.e., loose nuts). During its audit of the Bolting Integrity Program, the staff noticed that these inspections are conducted on 100 percent of components over the course of several walkdowns. The staff also noticed that the applicant's walkdown activities are consistent with the staff's recommendations for managing the aging of structural bolting in GALL Report AMP XI.S6, "Structures Monitoring." GALL Report AMP XI.S6 recommends periodic visual inspections (at least every 5 years) of structural bolting to identify loose or missing nuts. Based on its review of components associated with item 3.1.1-66, for which the applicant cited generic note A, the staff finds the applicant's proposal to manage the effects of aging using the Bolting Integrity Program acceptable because the preventive measures minimize the propensity for the bolting to lose preload and the periodic visual inspections are capable of identifying loss of preload of the structural bolting prior to loss of intended function.

3.1.2.1.6 Cracking Due to Stress Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-80, addresses SS or steel with SS cladding pressurizer relief tanks (non-ASME-Section-XI tank shells, heads, flanges, and nozzles) exposed to treated borated water greater than 60 °C (greater than 140 °F), which will be managed for cracking due to SCC. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry" and AMP XI.M32, "One-Time Inspection," to ensure that the aging effect is adequately managed. GALL Report AMP XI.M2 recommends using water chemistry control to manage aging by limiting the concentrations of chemical species that cause SCC within the acceptable ranges to minimize the environmental effect on SCC. In addition, GALL Report AMP XI.M32, "One-Time Inspection" confirms the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

During its review of components associated with LRA item 3.1.1-80 for which the applicant cited generic note C, the staff noticed that the LRA credits the Water Chemistry Program to manage the aging effect. The LRA also credits the One-Time Inspection Program that will confirm the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

In its review of LRA item 3.1.1-80, the staff noticed that in LRA Table 3.1.2-1 (Page 3.1-57), the applicant used LRA item 3.1.1-80 to manage cracking due to SCC for SS piping, piping components, and piping elements of the RCS, which are exposed to reactor coolant. The staff also noticed these components are associated with generic note C, indicating that these components are different from those which are evaluated in the GALL Report, but applicant's aging management is consistent with the GALL Report for material, environment, aging effect, and AMP. However, the staff noticed that the LRA does not clearly indicate whether these components are ASME Code Class components. In addition, the staff noticed that the LRA does not address why periodic inspections (e.g., ASME Code Section XI examinations) are not used to manage cracking for these piping, piping elements, and piping components exposed to reactor coolant.

By letter dated February 26, 2014, the staff issued RAI 3.1.1.80-1 requesting that the applicant clarify whether the subject piping, piping components, and piping elements of the RCS are ASME Code Class components. The staff also requested that the applicant clarify whether the ASME Code examination requirements are applicable for these components.

In its response dated March 28, 2014, the applicant stated that the piping, piping components, and piping elements attached to the RCS are ASME Code Class 2 components. The applicant also stated that these piping and connections are not required to be surface or volumetrically examined in accordance with the ASME Code requirements, because they are less than or equal to 1.5-in. NPS. In addition, the applicant provided the specific names and sizes of these piping and instrumentation tube components in its response.

The applicant stated that these ASME Code Class 2 components are inspected as part of the pressure testing (VT-2) for the RCS boundary. The applicant also indicated that since a VT-2 examination can only detect cracking after leakage occurs, the Water Chemistry Program and One-Time Inspection Program were credited for management of cracking as opposed to the ASME-Code-required VT-2 examination, which is consistent with the GALL Report. The applicant further stated that OE review was performed for the Byron and Braidwood units, and no evidence of cracking due to vibrations or SCC was found for the piping and instrumentation tubing components attached to the RCS.

In its review, the staff finds the applicant's response acceptable because the applicant confirmed that (1) these piping components are ASME Code Class 2 components that are less than or equal to 1.5-in. NPS, (2) periodic surface or volumetric examinations are not required for these components, (3) the One-Time Inspection Program will be used to ensure that cracking does not occur in these components before potential leakage occurs, and (4) ASME-Code-required VT-2 examination is periodically performed on these piping components. The staff's concern described in RAI 3.2.1.20-1 is resolved.

In a teleconference call held on May 12, 2014, the applicant also clarified that, as described in UFSAR Section 5.4.11, the normal operating temperature of the pressurizer relief tanks is less than 60 °C such that LRA item 3.1.1-80 is not applicable to these components. The staff reviewed UFSAR Section 5.4.11 and confirmed that LRA item 3.1.1-80 is not applicable to the pressurizer relief tanks as the applicant indicated.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.1.6, respectively. The Water Chemistry Program proposes to manage the effects of aging for the SS piping, piping components, and piping elements of the RCS through the use of water chemistry monitoring and control of known detrimental contaminants such as chloride, fluorides, DO, and sulfate concentrations below the levels known to result in cracking due to SCC. The One-Time Inspection Program proposes a one-time inspection of the representative sample size (i.e., 20 percent of the population up to a maximum of 25 component inspections) to ensure that no unacceptable aging-related degradation due to SCC is occurring.

Based on its review of components associated with Item 3.1.1-80, for which the applicant cited generic note C, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC within the acceptable ranges to minimize the environmental effect on SCC and because the One-Time Inspection Program includes a one-time inspection of representative components to confirm the effectiveness of the Water Chemistry Program.

The staff concludes that for LRA item 3.1.1-80, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.1.1, item 3.1.1-81, addresses SS pressurizer spray heads exposed to reactor coolant exposed to treated borated water greater than 60 °C (greater than 140 °F), which will be managed for cracking due to SCC. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry" and AMP XI.M32, "One-Time Inspection," to ensure that cracking due to SCC is adequately managed. GALL Report AMP XI.M2 recommends using water chemistry control to manage aging by limiting the concentrations of chemical species that cause SCC within the acceptable ranges to minimize the environmental effect on SCC. In addition, GALL Report AMP XI.M32, "One-Time Inspection" confirms the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

During its review of components associated with LRA item 3.1.1-81 for which the applicant cited generic note C, the staff noticed that the LRA credits the Water Chemistry Program to manage the aging effect. The LRA also credits the One-Time Inspection Program, which will confirm the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

In its review of LRA item 3.1.1-81, the staff noticed that in LRA Table 3.1.2-1, the applicant used LRA item 3.1.1-81 to manage cracking due to SCC for the tubes of RCP thermal barrier heat exchangers which are exposed to reactor coolant. The staff also noticed that the LRA does not identify any periodic inspection activities to manage cracking for these heat exchanger tubes. In addition, the staff noticed that UFSAR Section 11.5.2.3.2, "Component Cooling Water Monitors," indicates that applicant's radiation detectors continuously monitor the component cooling system for leakage of reactor coolant from the RCS and/or the RHR system.

The staff also noticed that the RCP thermal barrier heat exchanger tubes form the pressure boundary between the component cooling and RCSs. However, the staff noticed that the LRA does not identify any periodic inspections to manage cracking for these heat exchanger tubes. The staff further noticed that the LRA does not address whether applicant's OE, including the component cooling water monitoring activity of the UFSAR, confirms that cracking does not occur in the heat exchanger tubes.

By letter dated February 26, 2014, the staff issued RAI 3.1.1.81-1 requesting that the applicant justify why the LRA does not identify any periodic inspections to manage cracking for the RCP thermal barrier heat exchanger tubes. The staff also requested that, alternatively, the applicant identify periodic inspections to manage cracking for these components. The staff further requested that, as part of the response, the applicant confirm whether or not the heat exchanger tubes are ASME Code Class 1 components. In addition, the staff requested that the applicant clarify whether applicant's OE confirms that cracking does not occur in the heat exchanger tubes.

In its response dated March 28, 2014, the applicant stated that the RCP thermal barrier heat exchanger has reactor coolant (seal injection flow) on the outside of the tubes and component cooling (closed-cycle cooling water) on the inside of the tubes. The applicant also stated that this heat exchanger consists of only concentric tubes around the pump shaft (i.e., no shell, tube sheet, or tube side components) and is integral to the pump casing assembly. The applicant further stated that the RCP thermal barrier heat exchanger is an ASME Code Class 1 component.

In its response regarding the justification for using a one-time inspection, the applicant stated that the entire thermal barrier, including the heat exchanger subassembly, is a fully welded fabrication and that direct inspection of the thermal barrier heat exchanger tubes is not feasible on the applicant's RCPs. The applicant indicated that since periodic inspections of the thermal barrier heat exchanger tubes are not feasible, it is appropriate to use GALL Report Item 3.1.1-81, which manages the same aging effect for a different component but similar materials and environment. The applicant also stated that the Water Chemistry Program and One-Time Inspection Program together with the existing design features discussed above are used to justify that aging of the tubes for potential cracking will be adequately managed during the period of extended operation without periodic inspections.

In its response regarding the component cooling water monitoring, the applicant indicated that there are several measures that provide continuous monitoring of the RCP thermal barrier heat exchanger. The applicant also stated that monitoring for cracking of the thermal barrier heat exchanger tubes is performed by radiation monitors, which would detect an increase in radioactivity in the component cooling system, and the component cooling surge tank level alarms which would detect an unexpected increase in water level. The applicant further stated that high component cooling flow conditions are also monitored on the outlet lines of the heat exchangers to detect high flow which automatically initiate signals to isolate flow with the isolation valves inside containment. In addition, the applicant stated that station operating procedures provide appropriate actions should any of the above conditions occur.

In its response regarding the review of OE, the applicant stated that a review was conducted of the OE associated with the component cooling sample results for the past 5 years of operation. The applicant also stated that there have been no indications of RCP thermal barrier tube leaks based on the radioactivity level of the component cooling samples.

In its review, the staff finds the applicant's response acceptable because the applicant confirmed that (1) the design features of these components do not allow direct inspections unless a destructive disassembly is performed, (2) monitoring is performed on the radioactivity in the component cooling system and the flow conditions of the heat exchanger outlet lines to detect cracking of these components indirectly, (3) a review of the OE confirms that there have been no indications of RCP thermal barrier tube leaks based on the radioactivity level of the component cooling samples, and (4) the use of the Water Chemistry Program and One-Time

Inspection Program provides reasonable assurance that cracking due to SCC will be adequately managed for these components, based on the design features, monitoring activities, and OE review described above. The staff's concern described in RAI 3.1.1.81-1 is resolved.

During its review of the applicant's response and aging management related to LRA item 3.1.1-81, the staff noticed that LRA Table 3.1.2-1 for the RCS does not include an AMR line item that manages cracking due to SCC of SS pressurizer spray heads exposed to reactor coolant using LRA item 3.1.1-81. The staff could not determine how the applicant will manage cracking due to SCC of pressurizer spray heads.

By letter dated May 21, 2014, the staff issued RAI 3.1.1.81-1a requesting that the applicant clarify why LRA Table 3.1.2-1 does not include a specific AMR line item that manages cracking due to SCC of SS pressurizer spray heads using LRA item 3.1.1-81. The staff also requested that, alternatively, the applicant revise the LRA to identify an AMR line item which is associated with LRA item 3.1.1-81 to manage cracking due to SCC for these components.

In its response dated June 16, 2014, the applicant stated that upon further review of the CLB for crediting the chemical and volume control system (CVCS) auxiliary spray, AMR items associated with the pressurizer spray heads were added to the LRA. The applicant also indicated that the intended function of the pressurizer spray heads is to provide a method of pressure control by condensing the pressurizer steam bubble (i.e., spray function). The applicant further stated that the Water Chemistry Program and One-Time Inspection Program will be used to manage cracking due to SCC for these components. In addition, the applicant stated that the Water Chemistry Program will be used to manage loss of material due to pitting and crevice corrosion for these components.

The applicant also revised LRA Tables 2.3.1-1, 3.1.1, and 3.1.2-1 to identify the pressurizer spray heads as components subject to an AMR and to include new AMR items which will manage cracking and loss of material for these components as described above. The applicant cited generic note A for these new AMR items indicating that these AMR items are consistent with the GALL Report. The staff finds that the new AMR items are adequate to manage cracking and loss of material for the pressurizer spray heads, consistent with GALL Report Items IV.C2.RP-41 and IV.C2.RP-23.

In its response, the applicant also indicated that the pressurizer spray heads are fabricated from CF8M CASS. The applicant further indicated that the pressurizer spray heads do not perform any intended function at low temperatures. In addition, the applicant stated that since the stresses on the pressurizer spray heads at low temperatures are negligible and no mechanism exists to apply excessive loading, the pressurizer spray heads are not subject to loads that would result in a fracture (non-ductile failure) at low temperatures. The applicant stated that aging management of loss of fracture toughness due to thermal aging embrittlement is not required because the pressurizer spray head is not part of the ASME Class 1 RCPB, is not a pressure-retaining component, and is not a structural component. In a teleconference dated July 30, 2014, the applicant also confirmed that since the pressurizer spray head is only subject to low stresses at operating temperatures, there is no concern about fracture in this component as discussed in Section 3.3.4 of WCAP 14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," December 2000.

In its review, the staff finds the applicant's response regarding thermal aging embrittlement acceptable because the applicant confirmed that the pressurizer spray head is not a pressure-retaining component and is not subject to stresses that could cause fracture. As discussed above, the staff also finds that the applicant appropriately credited the One-Time Inspection Program to manage cracking for the pressurizer spray head, consistent with the GALL Report. The concern described in RAI 3.1.1.81-1a is resolved.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.1.6, respectively. The Water Chemistry Program proposes to manage the effects of aging for the SS RCP thermal barrier heat exchanger tubes and pressurizer spray heads through the use of the water chemistry monitoring and control of known detrimental contaminants such as chloride, fluorides, DO, and sulfate concentrations below the levels known to result in cracking due to SCC. The One-Time Inspection Program proposes a one-time inspection of the representative sample size (i.e., 20 percent of the population) to ensure that no unacceptable aging-related degradation due to SCC is occurring.

In its review of components associated with Item 3.1.1-81, for which the applicant cited generic notes A and C, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC within the acceptable ranges to minimize the environmental effect on SCC, and because the One-Time Inspection Program includes a one-time inspection of representative components to confirm the effectiveness of the Water Chemistry Program.

The staff concludes that for LRA item 3.1.1-81, the applicant 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).

3.1.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.1.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the RCS components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to SCC and IGSCC
- crack growth due to cyclic loading
- cracking due to SCC
- cracking due to cyclic loading
- loss of material due to erosion
- cracking due to SCC and IASCC
- loss of fracture toughness due to neutron irradiation embrittlement, change in dimension due to void swelling, loss of preload due to stress relaxation, or loss of material due to wear

- cracking due to PWSCC
- cracking due to fatigue
- cracking due to SCC and fatigue
- loss of material due to wear
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.1.2.2. The staff's review of the applicant's further evaluation follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 associated with LRA Table 3.1.1, items 3.1.1-1 through 3.1.1-11, addresses the applicant's AMR for managing cumulative fatigue damage in the RCS, reactor vessel, steam generators, CVCS, main steam system, and RVI components with a fatigue analysis. The applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Sections 4.3 and 4.7.

The applicant discussed the following items in LRA Table 3.1.1 that are applicable:

- Items 3.1.1-1 through 3.1.1-3 are associated with cumulative fatigue. The applicant stated that cumulative fatigue is a TLAA addressed in LRA Section 4.3 and 4.7.
- Item 3.1.1-5 is associated with cumulative fatigue. The applicant stated that cumulative fatigue is a TLAA addressed in LRA Section 4.3 and 4.7.
- Items 3.1.1-8 through 3.1.1-10 are associated with cumulative fatigue. The applicant stated that cumulative fatigue is a TLAA addressed in LRA Section 4.3 and 4.7.

For LRA Table 3.1.1, item 3.1.1-4, the applicant stated that the AMR item is not applicable because it has a Westinghouse reactor vessel that does not have support skirts. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for this item.

The staff noticed that Table 3.1.1, items 3.1.1-6, 3.1.1-7, and 3.1.1-11, are specifically related to components in a BWR design; therefore, the staff finds it appropriate that the applicant did not address these items in the LRA.

The staff reviewed LRA Section 3.1.2.2.1 against the further evaluation criteria in SRP-LR Section 3.1.2.2.1, which states that fatigue is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and consistent with SRP-LR Sections 4.3 and 4.7. The staff reviewed the AMRs line items associated with LRA Section 3.1.2.2.1 and determined that the AMR results are consistent with the GALL Report and SRP-LR.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.1.2.2.1 criteria. For those line items that apply to LRA Section 3.1.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Sections 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAAs for these components.

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

<u>Item 1</u>. LRA Section 3.1.2.2.2, item 1, associated with LRA Table 3.1.1, item 3.1.1-12, addresses loss of material due to general, pitting, and crevice corrosion for PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The LRA states that the existing program relies on control of the Water Chemistry Program to mitigate corrosion and the ASME ISI program to detect loss of material. The LRA also states that the steam generators for both units have been replaced and that none of its units have the high-stress region at the shell to transition cone weld found in Models 44 and 51 steam generators. Specifically, BBS Unit 1 steam generators were replaced in their entirety with B&W recirculating RSGs, while BBS Unit 2 steam generators are the original Westinghouse Model D-5 recirculating preheater type steam generators.

The GALL Report states that this aging effect for the component is limited to Westinghouse Models 44 and 51 steam generators, where a high-stress region exists at the shell to transition cone weld. In its review of components associated with item 3.1.1-12, the staff confirmed that the applicant's steam generators are B&W recirculating steam generators and Westinghouse Model D-5 recirculating steam generators, and the staff finds that the augmented inspection is not applicable to the applicant's steam generators.

<u>Item 2</u>. LRA Section 3.1.2.2.2, item 2, associated with LRA Table 3.1.1, item 3.1.1-12, addresses the steam generator upper and lower shell assembly and transition cone exposed to secondary feedwater and steam that, in SRP-LR, pertains to plants where partial steam generator replacements have been made. The applicant's Unit 1 steam generators were replaced in their entirety with B&W recirculating RSGs, and its Unit 2 steam generators are the original Westinghouse Model D-5 recirculating preheater type steam generators. Therefore, the LRA states that further evaluation of this GALL item is not applicable.

In its review of components associated with item 3.1.1-12, the staff confirmed that the applicant's steam generators do not have the associated field-weld in the middle of the steam generator's transition cone. Therefore, the staff finds that this item is not applicable to the applicant's steam generators.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

<u>Item 1</u>. LRA Section 3.1.2.2.3, item 1, associated with LRA Table 3.1.1, item 3.1.1-13, addresses steel (with or without SS cladding) reactor vessel beltline shells, nozzles, and welds exposed to a reactor coolant and neutron flux environment, which will be managed for loss of fracture toughness due to neutron irradiation embrittlement by the TLAAs in LRA Section 4.2 and its subsections.

The criteria in SRP-LR Section 3.1.2.2.3, item 1, state that evaluation of loss of material due to neutron irradiation embrittlement is a TLAA that is to be evaluated for the period of extended operation for all reactor vessel components that are made from ferritic steel materials (i.e., from carbon steels, low alloy steels, or cast irons) and are projected to have a cumulative neutron fluence exposure greater than 1.0×10^{17} n/cm^2 (E >1 MeV) at the end of the license renewal term.

The SRP-LR states that the recommendations for evaluating neutron embrittlement TLAAs are addressed separately in SRP-LR Section 4.2, "Reactor Vessel Neutron Embrittlement Analysis." The SRP-LR also indicates that the relevant AMR item for SRP-LR Section 3.1.2.2.3, item 1, is given in SRP-LR Table 3.1-1, AMR Item 13. This AMR item in the SRP-LR further references GALL Report AMR Item IV.A2.R-84 for managing loss of fracture toughness in steel reactor vessel beltline shells and associated weld components and GALL Report AMR Item IV.A2.R-81 for managing loss of fracture toughness in steel reactor vessel inlet and outlet nozzle components.

The staff reviewed the applicant's AMR basis to confirm its consistency with recommendations in SRP-LR Section 3.1.2.2.3, item 1; SRP-LR Table 3.1-1, AMR Item 13 in SRP-LR; and GALL Report AMR Items IV.A2.R-84 and IV.A2.R-81. In its review, the staff confirmed that the applicant appropriately credited its neutron embrittlement TLAAs as part of its basis for managing loss of fracture toughness due to neutron irradiation embrittlement in the applicable reactor vessel components during the period of extended operation. The staff also noticed that the applicant appropriately identified the applicable AMR items, which are associated with LRA item 3.1.1-13 in LRA Table 3.1.2-1.

The staff noticed that the applicable AMR items in LRA Table 3.1.2-1 include both the original set of reactor vessel beltline components (i.e., the reactor vessel intermediate shell forgings, reactor vessel lower shell forgings, and their associated reactor vessel circumferential shell-to-shell welds) and reactor vessel extended beltline components (i.e., the reactor vessel inlet and outlet nozzle forgings and their associated nozzle-to-shell welds). The staff also noticed that the applicant included these reactor vessel extended beltline components in the scope of the AMR items because the applicant had projected that the neutron fluence exposures of the reactor vessel inlet and outlet nozzles and their associated reactor vessel nozzle-to-shell welds would exceed the neutron fluence threshold of 1.0×10^{17} n/cm^2 (E>1 MeV) prior to the end of the period of extended operation. The staff found that the applicant's basis was consistent with the neutron fluence threshold-scoping requirement basis in 10 CFR Part 50, Appendix H, for defining reactor vessel components that are within the reactor vessel beltline region, including those reactor vessel components that would need to be identified as reactor vessel extended beltline components, as discussed above.

The staff confirmed that the applicant included its neutron embrittlement TLAAs in the following sections of the LRA: (a) LRA Section 4.2.1 for the TLAA on "Neutron Fluence Projections"; (b) LRA Section 4.2.2 for the TLAA on "Upper-Shelf Energy" (USE); (c) LRA Section 4.2.3 for the TLAA on "Pressurized Thermal Shock"; (d) LRA Section 4.2.4 for the TLAA on "Adjusted Reference Temperature"; (e) LRA Section 4.2.5 for the TLAA on "Pressure-Temperature (P-T) Limits"; and (f) LRA Section 4.2.6 for the TLAA on "Low Temperature Overpressure Protection (LTOP) Analyses." The staff also confirmed that the applicant's AMR basis for crediting these TLAAs was consistent with the AMR item criteria of GALL Report Item IV.A2.R-84 to manage loss of fracture toughness for PWR reactor vessel beltline shell and weld components and with those of GALL Report AMR Item IV.A2.R-81 to manage loss of fracture toughness for PWR reactor vessel inlet and outlet nozzle components.

The staff's evaluations of the TLAAs on reactor vessel neutron irradiation embrittlement are documented in SER Section 4.2, which includes staff's evaluations of the TLAAs on reactor vessel fluence, USE, PTS, ART, P-T Limits, and LTOP analyses. The staff evaluations of these TLAAs are documented in SER Sections 4.2.1, 4.2.2, 4.2.3, 4.2.4, 4.2.5, and 4.2.6, respectively.

Based on this review as described above, the staff finds the applicant's AMR basis to be acceptable because it is consistent with recommended bases in the following sections of the SRP-LR and GALL Report: (a) SRP-LR Section 3.1.2.2.3, item 1; (b) SRP-LR Table 3.1-1, AMR Item 13 ; and (c) GALL Report AMR Items IV.A2.R-84 and IV.A2.R-81.

Item 2. LRA Section 3.1.2.2.3, Subsection 2, associated with LRA Table 3.1.1, item 3.1.1-14, addresses steel (with or without SS cladding) reactor vessel beltline shell, nozzles, and welds exposed to a reactor coolant and neutron flux environment, which will be managed by the Reactor Vessel Surveillance program (LRA AMP B.2.1.19). The applicant stated that the Reactor Vessel Surveillance program provides sufficient material dosimetry data to monitor for neutron irradiation embrittlement for the period of extended operation and to determine whether additional operating restrictions on the cold leg operating temperature, neutron spectrum, and neutron fluence are needed for plant operations during the period of extended operation.

The criteria in SRP-LR Section 3.1.2.2.3, item 2, state that loss of fracture toughness due to neutron irradiation embrittlement could occur in PWR reactor vessel beltline shell, nozzle, and welds that are exposed to a reactor coolant and neutron flux environment. The SRP-LR also states that a reactor vessel materials surveillance program monitors for the degree of neutron irradiation embrittlement that is occurring in the reactor vessel and that the AMP is based on the requirements in 10 CFR Part 50, Appendix H. The SRP-LR further states that, under this regulation, an applicant is required to submit its proposed reactor vessel surveillance capsule withdrawal schedule or any changes to the existing reactor vessel surveillance capsule withdrawal schedule to the staff for approval prior to implementation.

In addition, SRP-LR Section 3.1.2.2.3, item 2, recommends that any untested reactor vessel surveillance capsules should be placed in storage and maintained for potential reinsertion to the reactor vessel. The relevant AMR item that is based on the recommendations in SRP-LR Section 3.1.2.2.3, item 2, is given in SRP-LR Table 3.1-1, AMR Item 14, which references GALL AMR Item IV.A2.RP-229 for managing loss of fracture toughness in steel reactor vessel beltline shells and associated weld components and GALL AMR Item IV.A2.RP-228 for managing loss of fracture toughness in steel reactor vessel inlet and outlet nozzle components.

The staff reviewed the applicant's AMR basis for consistency with recommendations in SRP-LR Section 3.1.2.2.3, item 2; AMR Item 14 in SRP-LR Table 3.1-1; and GALL AMR Items IV.A2.RP-228 and IV.A2.RP-229. The staff confirmed that the applicant includes the applicable AMP in LRA Section B.2.1.19, which is used as part of the applicant's basis for managing loss of fracture toughness due to neutron irradiation embrittlement in reactor vessel beltline and extended beltline components during the period of extended operation. The staff noticed that this AMP is based on compliance with the reactor vessel surveillance program and surveillance capsule withdrawal schedule requirements in 10 CFR Part 50, Appendix H.

The staff also noticed that the applicable AMR item in LRA Table 3.1.2-2 includes both the original set of reactor vessel beltline components (i.e., the reactor vessel intermediate shell forgings, reactor vessel lower shell forgings, and their associated reactor vessel circumferential shell-to-shell welds) and reactor vessel extended beltline components (i.e., the reactor vessel inlet and outlet nozzle forgings and their associated nozzle-to-shell welds). The staff also noticed that the applicant included these reactor vessel extended beltline components in the scope of the AMR items because the applicant had projected that the neutron fluence exposures of the reactor vessel inlet and outlet nozzles and their associated reactor vessel nozzle-to-shell welds would exceed the neutron fluence threshold of 1.0×10^{17} n/cm^2 (E>1 MeV) prior to the end of the period of extended operation. The staff found that the applicant's basis was consistent with the neutron fluence threshold-scoping requirement basis in 10 CFR Part 50, Appendix H, for defining reactor vessel components that are within the reactor vessel beltline region, including those reactor vessel components that would need to be identified as reactor vessel extended beltline components, as discussed above.

Therefore, based on this review, the staff finds the applicant's basis to be acceptable because it is consistent with recommended bases in the following sections of the SRP-LR and GALL reports: (a) SRP-LR Section 3.1.2.2.3, item 2; (b) AMR Item 14 in SRP-LR Table 3.1-1; and (c) GALL Report AMR Items IV.A2.RP-228 and IV.A2.RP-229.

The staff's evaluation of the Reactor Vessel Surveillance program is documented in SER Section 3.0.3.2.14.

<u>Item 3</u>. LRA Section 3.1.2.2.3, item 3, associated with LRA Table 3.1.1, item 3.1.1-15, addresses a potential plant-specific TLAA for managing loss of ductility properties in SS and nickel alloy RVI components that are exposed to a reactor coolant and neutron flux environment. The applicant stated that the aging management topic in SRP-LR Section 3.1.2.2.3, item 3, is not applicable to the BBS CLB because it only applies to PWR RVI components designed by the B&W. The applicant explained that Westinghouse designed the BBS RVI components.

The staff noticed that the reduction of ductility TLAA in TR No. BAW-2248-A, as referenced in SRP-LR Section 3.1.2.2.3, item 3, is the topic of and only applicable to the RVI components at PWR facilities designed by B&W. The staff noticed that UFSAR Section 1.1, "Introduction," identifies that the NSSS components (which include the RVI components) for the BBS reactor units were designed and furnished by Westinghouse.

Therefore, based on this review, the staff finds that the applicant has provided an acceptable basis for concluding the ductility reduction analysis in TR No. BAW-2248-A and that the recommendations in SRP-LR Section 3.1.2.2.3, item 3, are not applicable to the BBS CLB because the staff has confirmed that the RVI components were not designed by B&W. Instead, the staff has confirmed that the applicant will manage the aging effects that are applicable to the RVI components through implementation of the applicant's PWR Vessel Internals Program, which is described in LRA Section B.2.1.7. The staff's evaluation of the PWR Vessel Internals Program is documented in SER Section 3.0.3.2.3.

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

<u>Item 1</u>. LRA Section 3.1.2.2.4, item 1, associated with LRA Table 3.1.1, item 3.1.1-16, addresses cracking in SS and nickel alloy BWR reactor vessel flange leakage detection lines exposed to a reactor coolant leakage environment. The criteria in SRP-LR Section 3.1.2.2.4, item 1, states that a plant-specific AMP should be evaluated based on the acceptance criteria in SRP-LR Section A.1 because existing programs may not be capable of mitigating or detecting cracking due to SCC and IGSCC. The applicant stated that this item is not applicable because it is only for BWRs, and the reactors at BBS are PWRs. The staff evaluated the applicant's

claim and finds it acceptable because, per the UFSAR, the reactors at BBS are PWRs and do not include BWR reactor vessel flange leakage detection lines.

LRA Section 3.1.2.2.6, item 1, associated with LRA Table 3.1.1, item 3.1.1-19, provides the applicant's AMR for cracking due to SCC in the PWR reactor vessel flange leakage detection lines at BBS. SER Section 3.1.2.2.6, item 1, documents the staff's evaluation of this AMR item.

Item 2. LRA Section 3.1.2.2.4, Subsection 2, associated with LRA Table 3.1.1, item 3.1.1-17, addresses cracking in SS BWR isolation condenser components exposed to reactor coolant. The criteria in SRP-LR Section 3.1.2.2.4, item 2, state that existing programs should be augmented to detect cracking in these components due to SCC and IGSCC, and SRP-LR Section A.1 provides the acceptance criteria. The applicant stated that this item is not applicable because it is only for BWRs, and BBS are PWRs. The staff evaluated the applicant's claim and finds it acceptable because, per the UFSAR, BBS are PWRs, and their ESF systems do not include or rely on isolation condenser components for RHR or shutdown cooling functions during scheduled reactor shutdowns, anticipated design basis transient events, or postulated DBAs.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5, associated with LRA Table 3.1.1, item 3.1.1-18, addresses intergranular separations (underclad cracks) in welds used to join cladding to RPV shell or nozzle forgings made from SA-508 Class 2 alloy steel materials using a high heat input welding process and exposed to the reactor coolant environment. The LRA states that this item is not applicable for BBS because the reactor vessel shells are not fabricated using a high heat input welding process.

SRP-LR Section 3.1.2.2.5 identifies that crack growth due to cyclic loading could occur in reactor vessel shell forgings clad with SS using a high-heat-input welding process. The SRP-LR states that growth of intergranular separations in the heat-affected zone under austenitic SS cladding may need to be identified as a TLAA for the period of extended operation.

The staff noticed that UFSAR Section 5.2.3.3.2 states that all welding is conducted utilizing procedures qualified in accordance with the rules of Sections III and IX of the ASME code. In regard to the control of processes used to weld SS cladding to LAS RPV forging components, UFSAR Section 5.2.3.3.2 states that qualification of any high heat input process is required and is performed in accordance with accepted industry protocols and guidelines. The staff confirmed that UFSAR Appendix A states that BBS implemented industry welding protocols that were performed in accordance RG 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components" in order to address potential cracking of RPV cladding-to-forging component welds. The staff specifically noticed that UFSAR Appendix A identifies that the intent of RG 1.43 was met by requiring qualification of any high heat input welding processes that were used to join the cladding to these types of RPV forging components. The staff also noticed the applicant's past implementation of these performance tests was consistent with recommended criteria in Regulatory Position 2 of the RG.

Therefore, based on the information above, the staff concludes that the criteria in SRP-LR Section 3.1.2.2.5, and therefore item 3.1.1-18, do not apply to the LRA because the staff confirmed that: (a) the applicant does not rely on a TLAA as the basis for managing crack growth due to cyclical loading (i.e., underclad cracking) in the RPV cladding welds, and

(b) instead, the applicant has addressed potential underclad cracking through implementation of past welding process protocols that are in conformance with the recommended criteria in RG 1.43.

3.1.2.2.6 Cracking Due to Stress Corrosion Cracking

Item 1. LRA Section 3.1.2.2.6, item 1, associated with LRA Table 3.1.1, item 3.1.1-19, addresses the management of cracking in PWR reactor vessel flange leak detection lines and reactor vessel bottom-mounted instrumentation (BMI) guide tubes exposed to a reactor coolant environment. The criteria in SRP-LR Section 3.1.2.2.6, item 1, state that cracking due to an SCC mechanism could occur in PWR reactor vessel flange leak detection lines and BMI guide tubes that are exposed to a reactor coolant environment. SRP-LR Section 3.1.2.2.6, item 1, also states that the GALL Report recommends further evaluation to ensure that this aging effect will be adequately managed and that a plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed during the period of extended operation. Acceptance criteria are described in Branch Technical Position RLSB-1.

The applicant addressed the further evaluation criteria in SRP-LR Section 3.1.2.2.6, item 1, by stating that cracking of the BMI guide tubes will be managed using a combination of the applicant's Water Chemistry Program and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant also identified that cracking of the reactor vessel flange leak detection line will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

In its review of components associated with item 3.1.1-19, the staff finds that for the SS BMI guide tubes, the applicant has met the further evaluation criteria. The LRA states that SCC of the BMI guide tubes is managed by the Water Chemistry Program and is also managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed LRA Section 3.1.2.2.6 against the criteria in SRP-LR Section 3.1.2.2.6, item 1, which states that cracking due to SCC could occur in PWR SS bottom-mounted instrument guide tubes exposed to reactor coolant. The SRP-LR also states that the GALL Report recommends that a plant-specific AMP be evaluated to ensure that this aging effect is adequately managed. SER Sections 3.0.3.1.1 and 3.0.3.2.1 document the staff's evaluation of the applicant's Water Chemistry and ASME Section XI ISI, Subsections IWB, IWC, and IWD programs respectively. In its review of the SS BMI guide tubes associated with LRA Table 3.1.1, item 3.1.1-19, the staff finds the applicant's proposal to manage aging using the Water Chemistry and ASME Section XI ISI programs acceptable because the Water Chemistry Program will mitigate the potential for SCC by limiting and controlling contaminants that may contribute to SCC, while the ASME Section XI ISI, Subsections IWB, IWC, and IWD, program will verify the effectiveness of the Water Chemistry Program. Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.6, item 1, criterion to manage the aging effects for the stainless BMI guide tubes.

In its review of the applicant's reactor vessel flange leak detection lines, which are also associated with LRA Table 3.1.1, item 3.1-19; the staff noticed that the applicant stated that its reactor vessel flange leak detection line is made of SS with a normal operating environment of air with borated water leakage. In addition, the applicant stated that SCC of the reactor vessel flange leak detection line will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. As part of the program, the applicant has proposed using visual examinations (VT-2) to identify any cracking, if present. The staff finds the applicant's proposal to manage aging of the reactor vessel flange leak detection line using the

ASME Section XI ISI program acceptable because, during normal operation of the reactor, the environment for the applicant's reactor vessel flange leak detection line would be air with borated water leakage. In addition, the applicant's reactor vessel flange leak detection line is fabricated from SS. The staff noticed that the GALL Report includes entries for SSs exposed to air with borated water leakage. These entries indicate that an AERM is not present for this material and environment combination. In an unlikely scenario when there is cracking, the visual examinations (VT-2) would identify any indication of borated water leakage, if present. Therefore, the staff finds that the applicant's proposal to use its ASME Section XI ISI, Subsections IWB, IWC, and IWD, program acceptable.

Based on the programs identified, the staff determines that the applicant's programs meet the criteria in SRP-LR Section 3.1.2.2.6, item 1. For the items associated with LRA Section 3.1.2.2.6, item 1, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

Item 2. LRA Section 3.1.2.2.6, item 2, associated with LRA Table 3.1.1, item 3.1.1-20, addresses CASS Class 1 piping, piping components, and piping elements exposed to reactor coolant, which do not meet the NUREG-0313 guidelines with regard to ferrite and carbon contents. The LRA states that for these CASS components the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to manage cracking due to SCC. The LRA also states that the Water Chemistry (B.2.1.2) program minimizes contaminants that promote SCC and that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes condition monitoring activities of RCPB CASS components susceptible to cracking due to SCC to ensure that there is no loss of intended function.

In its review of components associated with LRA Table 3.1.1, item 3.1.1-20, the staff noticed that LRA Section 3.1.2.2.6, item 2 does not provide specific information for the "condition monitoring activities." By letter dated January 21, 2014, the staff issued RAI 3.1.2.2.6.2-1 requesting that the applicant provide additional information on the "condition monitoring activities" to demonstrate the adequacy of the applicant's aging management for these CASS components (e.g., how the conditions of these CASS components will be monitored and what inspection method will be used).

In its response dated February 27, 2014, the applicant stated that LRA Section 3.1.2.2.6, item 2, ASME Class 1 CASS components at BBS consist of the reactor coolant pipe fittings (elbows) for line item 3.1.1-20, IV.C2.R-05. The applicant also stated that the material screening criteria used to further evaluate and manage cracking due to SCC for these Class 1 CASS components are consistent with GALL Report item IV.C2.R-05. The applicant further stated that the recommended AMPs for this aging effect and aging mechanism in the GALL Report are the Water Chemistry Program and a plant-specific program. The applicant further stated that its CASS pipe fittings do not meet the NUREG-0313 material screening 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 for the resistance of CASS materials to SCC.

In addition, the applicant stated that for CASS pipe fittings at BBS, the condition monitoring activities referred to in LRA Section 3.1.2.2.6.2 consist of either a visual examination, a qualified ultrasonic test (UT) examination method, or a pressurized leakage test to monitor cracking in CASS pipe fittings. The applicant also stated that current UT methods cannot reliably detect and size cracks due to SCC in CASS components. The applicant further stated that a visual examination is planned to be used until a qualified UT examination methodology for CASS pipe fittings can be developed to meet the ASME Section XI, Appendix VIII, "Performance Demonstration for Ultrasonic Examination Systems" requirements. The applicant stated that the CASS pipe fittings are presently monitored in the ASME Section XI Inservice Inspection Program by using VT-2 examination at normal operating temperature and pressure. The applicant also stated that it is working with ASME and EPRI to develop a qualified examination method for the detection of SCC in CASS components.

The staff finds the applicant's response acceptable because the applicant clarified that, (a) it will monitor the CASS piping components susceptible to SCC using VT-2 examinations under its ASME Section XI Inservice Inspection Program until a qualified UT examination methodology is developed for these components, and (b) it is currently working with ASME and EPRI to develop a qualified examination method for detection of SCC in CASS components. The staff's concerns expressed in RAI 3.1.2.2.6.2-1 are resolved.

The staff finds the applicant's proposal to manage aging using the Water Chemistry Program and the ISI program acceptable because the Water Chemistry Program will mitigate the potential for SCC, while the ISI program using a VT-2 examination will verify the effectiveness of the Water Chemistry Program until a qualified UT examination methodology for SCC in CASS is developed. The staff's evaluations of the applicant's Water Chemistry Program and ASME Section XI Inservice Inspection Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.2.1, respectively.

Based on the programs identified, the staff determines that the applicant's program meets the criteria in SRP-LR Section 3.1.2.2.6, item 2. For the items associated with LRA Section 3.1.2.2.6, item 2, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will 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 Cyclic Loading

LRA Section 3.1.2.2.7, associated with LRA Table 3.1.1, item 3.1.1-21, addresses cracking in SS BWR isolation condenser components exposed to reactor coolant. The criteria in SRP-LR Section 3.1.2.2.7 state that existing programs should be augmented to detect cracking in these components due to cyclical loading, and SRP-LR Section A.1 provides the acceptance criteria. The applicant stated that this item is not applicable because it is only for BWRs, and Byron and Braidwood are PWRs. The staff evaluated the applicant's claim and finds it acceptable because, per the UFSAR, Byron and Braidwood are PWRs and their ESF systems do not include or rely on isolation condenser components for RHR or shutdown cooling functions during scheduled reactor shutdowns, anticipated design basis transient events, or postulated DBAs.

3.1.2.2.8 Loss of Material Due to Erosion

LRA Section 3.1.2.2.8, associated with LRA Table 3.1.1, item 2.1.1-22, addresses loss of material due to erosion for steam generator feedwater impingement plates exposed to secondary feedwater. The LRA states that the applicant's steam generators do not have feedwater impingement plates; therefore, the applicable GALL Report line item was not used.

The GALL Report recommends further evaluation of a plant-specific AMP for the management of loss of material due to erosion of steam generator feedwater steel impingement plates and supports exposed to secondary feedwater. In its review of components associated with the applicant's steam generator feedwater impingement plates (3.1.1-22), the staff confirmed that the applicant's steam generators do not have feedwater impingement plates. The staff finds that this item is not applicable to the applicant's steam generators.

3.1.2.2.9 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

LRA Section 3.1.2.2.9 associated with LRA Table 3.1.1 item 3.1.1-23 states that cracking of SS and nickel-alloy RVI components exposed to reactor coolant with neutron flux in the RVIs will be managed by the PWR Vessel Internals Program.

The staff noticed that Final LR-ISG-2011-04 was issued May 28, 2013, and that SRP-LR Section 3.1.2.2.9 was removed and is no longer applicable. The staff noticed that the applicant provided its response to A/LAIs to the staff's safety evaluation, Revision 1, for the MRP-227-A in LRA Appendix C. The staff noticed that staff's evaluation of the PWR Vessel Internals Program and A/LAI responses is documented in SER Section 3.0.3.2.3.

3.1.2.2.10 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement, Change in Dimension Due to Void Swelling, Loss of Preload Due to Stress Relaxation, or Loss of Material Due to Wear

LRA Section 3.1.2.2.10 associated with LRA Table 3.1.1 item 3.1.1-24 states that loss of fracture toughness, change in dimension, loss of preload, and loss of material of SS and nickel-alloy RVI components exposed to reactor coolant with neutron flux in the RVIs will be managed by the PWR Vessel Internals Program.

The staff noticed that Final LR-ISG-2011-04 was issued May 28, 2013, and that SRP-LR Section 3.1.2.2.10 was removed and is no longer applicable. The staff noticed that the applicant provided its response to A/LAIs to the staff's safety evaluation, Revision 1, for the MRP-227-A in LRA Appendix C. The staff noticed that staff's evaluation of the PWR Vessel Internals Program and A/LAI responses is documented in SER Section 3.0.3.2.3.

3.1.2.2.11 Cracking Due to Primary Water Stress Corrosion Cracking

LRA Section 3.1.2.2.11 associated with LRA Table 3.1.1, item 3.1.1-25 addresses steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant, which will be managed for cracking due to PWSCC. For the AMR items that cite generic note E, the LRA credits the Steam Generators program to manage the aging effect for steam generator primary side divider plate and steam generator tube-to-tubesheet welds. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M2 recommends monitoring and controlling the chemical environments of systems and components exposed to reactor coolant, steam, treated borated water, and treated water, such that aging effects of system components are minimized.

The staff's evaluation of the applicant's Water Chemistry and Steam Generators programs is documented in SER Sections 3.0.3.1.1 and 3.0.3.2.5, respectively. The staff noticed that the Water Chemistry program proposes to manage the effects of aging for steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds by monitoring and controlling system and component chemical environments. The Steam Generators program proposes to take one of the following three options to disposition PWSCC of the divider plate welds: (1) perform a one-time inspection capable of detecting cracks and assess the condition, (2) perform an analytical evaluation which concludes that the RCS pressure boundary will be maintained with divider plate weld cracking, or (3) evaluate results of industry and NRC studies that document that this aging effect is not a credible concern. The Steam Generators program also proposes to manage PWSCC of the tube-to-tube sheet welds exposed to reactor coolant by performing one of the following three options: (1) perform a one-time inspection capable of detecting cracks to resolve the condition, (2) perform an analytical evaluation to determine that the welds are not susceptible to PWSCC, or (3) perform an analytical evaluation of the welds redefining the RCS pressure boundary of the tubes; thereby, excluding the welds from performing an RCS pressure boundary function. The analytical evaluations performed by the applicant will be submitted to the staff for review and approval prior to entering the period of extended operation. In its response dated March 4, 2014, the applicant stated that if options 2 (PWSCC of the divider plate and tube-to-tubesheet welds) or 3 (PWSCC of the tube-to-tubesheet weld) are taken it will provide the analysis two years prior to the period of extended operation.

Based on its review of components associated with item 3.1.1-25 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage the effects of aging using the Steam Generators program acceptable because by performing one of the above three options, the applicant will be able to manage PWSCC of steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant.

3.1.2.2.12 Cracking Due to Fatigue

LRA Section 3.1.2.2.12 associated with LRA Table 3.1.1, item 3.1.1-26, states that this paragraph in the SRP-LR is not applicable to Byron and Braidwood, which are Westinghouse PWRs, because the paragraph pertains to CE PWRs.

The staff determined that SRP-LR Section 3.1.2.2.12 associated with cracking due to fatigue for RVIs designed by Combustion Engineering is not applicable to the applicant's site because Units 1 and 2 are a Westinghouse designed plant. The staff noticed that Final LR-ISG-2011-04 was issued May 28, 2013, and that SRP-LR Section 3.1.2.2.12 was removed and is no longer applicable. The staff noticed that cracking due to fatigue for RVIs is addressed by the I&E guidelines in MRP-227-A and the Reactor Vessel Internals Program. The staff noticed that the applicant provided its response to A/LAIs to the staff's safety evaluation, Revision 1, for the MRP-227-A in LRA Appendix C. The staff noticed that staff's evaluation of the PWR Vessel Internals Program and A/LAI responses is documented in SER Section 3.0.3.2.3.

3.1.2.2.13 Cracking Due to Stress Corrosion Cracking and Fatigue

LRA Section 3.1.2.2.13 associated with LRA Table 3.1.1, item 3.1.1-27, states that this paragraph in the SRP-LR is not applicable to Byron and Braidwood because the CRGT assemblies and guide tube support pins (split pins) at Byron and Braidwood are made of SS.

The staff noticed that Final LR-ISG-2011-04 was issued May 28, 2013, and that SRP-LR Section 3.1.2.2.13 was removed and is no longer applicable. The staff noticed that the applicant provided its response to A/LAIs to the staff's safety evaluation, Revision 1, for the

MRP-227-A in LRA Appendix C. The staff noticed that staff's evaluation of the PWR Vessel Internals Program and A/LAI responses is documented in SER Section 3.0.3.2.3.

3.1.2.2.14 Loss of Material Due to Wear

LRA Section 3.1.2.2.14 associated with LRA Table 3.1.1, item 3.1.1-28, states that this paragraph in the SRP-LR is not applicable to Byron and Braidwood because the CRGT assemblies and guide tube support pins (split pins) at Byron and Braidwood are made of SS and because the Byron and Braidwood Westinghouse RVIs do not use Zircaloy-4 incore instrumentation lower thimble tubes.

The staff noticed that Final LR-ISG-2011-04 was issued May 28, 2013, and that SRP-LR Section 3.1.2.2.14 was removed and is no longer applicable. The staff noticed that the applicant provided its response to A/LAIs to the staff's safety evaluation, Revision 1, for the MRP-227-A in LRA Appendix C. The staff noticed that staff's evaluation of the PWR Vessel Internals Program and A/LAI responses is documented in SER Section 3.0.3.2.3.

3.1.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.1.2.2.16 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of OE of AMPs.

3.1.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.1.2-1 through 3.1.2-4, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.1.2-1 through 3.1.2-4, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR 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 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. 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

<u>Carbon and Low Alloy Steel (with or without stainless steel cladding) Pressurizer and Steam Generator Components Exposed to Air with Borated Water Leakage</u>. In LRA Tables 3.1.2-1 and 3.1.2-4, the applicant stated that loss of material due to general, pitting, and crevice corrosion does not apply to various carbon and low alloy steel (with or without SS cladding) pressurizer and steam generator components exposed to air with borated water leakage. The AMR items cite LRA item 3.1.1-49, which are associated with loss of material due to boric acid corrosion. The AMR items also cite plant-specific notes stating that the components have an external temperature greater than 212 °F (100 °C) and, therefore, wetting due to condensation and moisture accumulation will not occur.

The staff reviewed the associated items in the LRA to confirm that loss of material due to general, pitting, and crevice corrosion is not applicable for the subject components. The staff noticed that LRA Table 3.0-1 states that the air with borated water leakage environment is similar to the air-indoor uncontrolled environment, which is described as an environment where the surfaces of components may be wetted, but only rarely. The staff also noticed that, during refueling outages, these components will be at ambient temperatures for prolonged periods of time, which may or may not be above the dew point. Therefore, they may be susceptible to a condensation environment during outages. The GALL Report recommends that GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” be used to manage loss of material due to general, pitting, and crevice corrosion for steel components exposed to uncontrolled indoor air. Therefore, by letter dated February 6, 2014, the staff issued RAI 3.1.1-1 requesting that the applicant justify why loss of material due to general, pitting, and crevice corrosion is not applicable, given that, during normal plant events such as refueling outages, these components will be at or near ambient temperatures.

In its response dated February 27, 2014, the applicant provided supporting information regarding why condensation and moisture accumulation will not occur on the pressurizers and steam generators. The applicant stated that condensation is limited by the use of the containment ventilation system to cool and dehumidify containment during outages and that insulation minimizes the extent of cooling of surfaces of the pressurizers and steam generators. The applicant also stated that a review of OE and past maintenance activities revealed no evidence of loss of material for these components. The applicant revised the plant-specific notes associated with the AMR items to state that the aging effects for these components were considered for both normal operating and outage conditions.

The staff finds the applicant’s response acceptable because the applicant demonstrated that containment atmospheric controls during outages have been effective at limiting condensation and moisture accumulation on the carbon steel pressurizer and steam generator external surfaces, such that there has been no OE associated with loss of material on these components. The staff’s concern described in RAI 3.1.1-1 is resolved. As a result, the staff finds the applicant’s proposal not to manage loss of material due to general, pitting, and crevice corrosion for the subject components acceptable.

On the basis of its review, the staff concludes for items in LRA Table 3.1.2-1 with no AERMs that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.2 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 system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the reactor vessel system component groups are consistent with the GALL Report.

3.1.2.3.3 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 RVIs system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the RVIs system component groups are consistent with the GALL Report.

3.1.2.3.4 Steam Generators—Summary of Aging Management Evaluation—LRA Table 3.1.2-4

Carbon and Low Alloy Steel (with or without stainless steel cladding) Steam Generator Components Exposed to Air with Borated Water Leakage. The staff's evaluation for carbon and low alloy steel (with or without SS cladding) steam generator components exposed to air with borated water leakage, for which the LRA cites plant-specific note 4, stating that high surface temperatures preclude loss of material due to general, pitting, and crevice corrosion, is documented in SER Section 3.1.2.3.1.

Cast Austenitic and Martensitic Stainless Steel Steam Generator Tube Support Lattice Bar Attachment Components Exposed to Treated Water Greater than 482 °F. In LRA Table 3.1.2-4, the applicant stated that Byron Station and Braidwood Station, Unit 1, martensitic SS steam generator tube support lattice bar and CASS steam generator tube support lattice bar attachment components exposed to treated water greater than 482 °F will be managed for loss of fracture toughness by the Steam Generators Program. The AMR items cite generic note H and plant-specific notes 3 and 6, which state that steam generator tube support lattice bar (SA-240 410S martensitic SS) and attachment (SA-351 CF3M CASS) components are potentially susceptible to loss of fracture toughness due to thermal aging embrittlement. These components are structural components internal to the secondary side of the steam generator and exposed to temperatures greater than 482 °F.

The staff noticed that this material and environment combination is not identified in the GALL Report. By letter dated April 10, 2014, the staff issued RAI 3.1.2.3.4-1 requesting that the applicant provide a description of the above components (including their function) and the extent to which they are used throughout the steam generator.

In its response dated May 12, 2014, the applicant stated that the possibility that the loss of fracture toughness would render the component incapable of performing its intended function without the component showing any visual evidence of cracking, deformation, or damage is negligible based on:

- The Unit 1 RSGs will still be a relatively young age at the end of the period of extended operation.
- The components are not pressure-retaining.

- The martensitic SS components are not precipitation-hardened and the operating temperature is below the threshold for "reversible temper embrittlement."
- The CASS components do not perform an intended function at low temperatures, and there are no significant stresses or loads on the CASS components at low temperatures.

The applicant also stated that the concern associated with thermal aging embrittlement of CASS material is the reduction in fracture toughness at low temperatures (i.e., room temperature) and the potential for non-ductile failure at low temperatures. The material properties at high temperature are not affected.

Furthermore, the applicant revised LRA Table 3.1.2-4 by deleting the AMR line items that state that Byron Station and Braidwood Station, Unit 1 steam generator tube support lattice bar and attachment components exposed to treated water greater than 482 °F will be managed for loss of fracture toughness by the Steam Generators program. In addition, the applicant stated that the aging effect or mechanism of loss of fracture toughness due to thermal aging embrittlement is not applicable to LRA Table 3.1.2-4, line item Steam Generators (internal supports and structures and tube support plates and U-bend supports).

The staff reviewed the applicant's response dated May 12, 2014, and notes that martensitic SSs exposed to temperatures above 750 °F and precipitation-hardened martensitic SSs exposed to aging temperatures of 485 °F may be susceptible to thermal aging embrittlement as described in NUREG/CR-6929, "Expert Panel Report on Proactive Materials Degradation Assessment." The martensitic components identified by the applicant are not precipitation hardened and are not exposed to temperatures that will cause significant loss of fracture toughness due to thermal aging embrittlement.

In addition, the staff notes that CASS components exposed to operating temperatures of 536-662 °F can lead to changes in the mechanical properties, depending on the characteristics of the material and the environment to which the component is exposed. This would include the CASS components previously identified by the applicant as being susceptible to loss of fracture toughness due to thermal aging embrittlement and was subsequently determined not to be susceptible to this aging effect. By letter dated June 26, 2014, the staff issued RAI 3.1.2.3.4-1a requesting that the applicant provide information on the composition, ferrite content, and fabrication method to determine if the CASS components are susceptible to thermal aging embrittlement in accordance with the guidance of NUREG-1801, Revision 2, Section XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."

In its response dated July 25, 2014, the applicant provided the material composition of the CASS components. The applicant identified that the ferrite contents of the CASS components, all below 10.3 percent, are significantly less than the 14 percent ferrite content criterion at which SA-351 CF3M CASS material becomes susceptible to thermal aging embrittlement, as described in NUREG-1801, Revision 2, Section XI.M12. Meeting this criterion means that the materials are expected to exhibit high enough fracture toughness levels that loss of fracture toughness due to thermal aging embrittlement is not significant.

After reviewing the applicant's response dated July 25, 2014, the staff finds that the steam generator tube support lattice bar (SA-240 410S martensitic SS) components are not susceptible to thermal aging embrittlement because the components are not precipitation hardened and because the operating conditions are well below the temperature threshold at which thermal aging embrittlement is likely to occur. In addition, the staff finds that the lattice bar attachment (SA-351 CF3M CASS) components are not susceptible to significant thermal aging embrittlement because the components are composed of materials with much less than 14 percent ferrite content, specifically less than 10.3 percent. These parameters make the martensitic and CASS components not susceptible to significant loss of fracture toughness due to thermal aging embrittlement per NUREG-1801, Revision 2, Section XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." The staff concern described in RAIs 3.1.2.3.4-1 and 3.1.2.3.4-1a is resolved.

Steam Generator Tubes (nickel alloy) Exposed to Treated Water. In LRA Table 3.1.2-4, the applicant stated that nickel alloy steam generator tubes exposed to treated water will be managed for reduction of heat transfer by the Steam Generators and the Water Chemistry AMPs. The AMR item cites generic note H and plant-specific note 8, which state that the reduction in 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 material and environment combination is identified in the GALL Report, which states that nickel alloy steam generator tubes exposed to secondary water (external) are susceptible to cracking, loss of material, and cumulative fatigue damage. The GALL Report recommends AMP XI.M19, Steam Generators, and XI.M2, Water Chemistry, to manage the aging effects. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.1.2-4. The applicant also identified reduction of heat transfer as an additional aging effect.

The staff's evaluations of the applicant's Water Chemistry and Steam Generators programs are documented in SER Sections 3.0.3.1.1 and 3.0.3.2.5, respectively. The staff finds the applicant's proposal to manage reduction of heat transfer using the Water Chemistry and Steam Generator AMPs acceptable because maintaining proper secondary water chemistry will minimize the amount of sludge deposits that can lead to a reduction in heat transfer in the steam generators. Additionally, periodic cleaning of the steam generator secondary side internals, including tubes and tubesheet, will remove accumulated deposits from the steam generator thus ensuring that the heat transfer ability of the tubes is not hindered.

On the basis of its review, the staff concludes for items in LRA Table 3.1.2-4 with no AERMs that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and RCS components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will 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 Systems

This section of the SER documents the staff's review of the applicant's AMR results for the ESF systems components and component groups of the following systems:

- combustible gas control system
- containment spray system (CSS)
- residual heat removal (RHR) system
- safety injection system (SIS)

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF systems components and component groups. LRA Table 3.2.1, “Summary of Aging Management Evaluations for the Engineered Safety Features,” provides a summary comparison of its AMRs to those evaluated in the GALL Report for ESF systems components and component groups.

The applicant’s AMRs evaluated and incorporated applicable plant-specific and industry OE 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 OE included a review of the GALL Report and OE issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

Table 3.2-1 Staff Evaluation for Engineered Safety Features Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel piping, piping components, and piping elements exposed to treated water (borated) (3.2.1-1)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation. See the SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)) .	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.2.2.2.1)
Steel (with stainless steel cladding) pump casings exposed to treated water (borated) (3.2.1-2)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.2.2.2.2)
Stainless steel partially-encased tanks with breached moisture barrier exposed to Raw water (3.2.1-3)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottom because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering.	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.2.2.2.3(1))
Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor (3.2.1-4)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components program	Not applicable to Byron and Braidwood (see SER Section 3.2.2.2.3(2))

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel orifice (miniflow recirculation) exposed to treated water (borated) (3.2.1-5)	Loss of material due to erosion	A plant-specific AMP is to be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging. See LER 50-275/94-023 for evidence of erosion.	Yes	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report (see SER Section 3.2.2.2.4)
Steel drywell and suppression chamber spray system (internal surfaces): flow orifice; spray nozzles exposed to air – indoor, uncontrolled (Internal) (3.2.1-6)	Loss of material due to general corrosion; fouling that leads to corrosion	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.5)
Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor (3.2.1-7)	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.2.2.2.6)
Aluminum, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-8)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report
Steel external surfaces, bolting exposed to air with borated water leakage (3.2.1-9)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report
CASS piping, piping components, and piping elements exposed to treated water (borated) >250 °C (>482 °F), treated water >250 °C (>482 °F) (3.2.1-10)	Loss of fracture toughness due to thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam, treated water (3.2.1-11)	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable	Not applicable to PWRs
Steel, high-strength closure bolting exposed to air with steam or water leakage (3.2.1-12)	Cracking due to cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood
Steel; stainless steel bolting, closure bolting exposed to air – outdoor (external), air – indoor, uncontrolled (external) (3.2.1-13)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program	Consistent with the GALL Report
Steel Closure bolting exposed to Air with steam or water leakage (3.2.1-14)	Loss of material due to general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood
Copper alloy, nickel alloy, steel; stainless steel, stainless steel, steel; stainless steel bolting, closure bolting exposed to any environment, air – outdoor (external), raw water, treated borated water, fuel oil, treated water, air – indoor, uncontrolled (external) (3.2.1-15)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program	Consistent with the GALL Report
Steel containment isolation piping and components (Internal surfaces), piping, piping components, and piping elements exposed to Treated water (3.2.1-16)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum, Stainless steel piping, piping components, and piping elements exposed to Treated water (3.2.1-17)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to PWRs
Stainless steel containment isolation piping and components (internal surfaces) exposed to treated water (3.2.1-18)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel heat exchanger tubes exposed to treated water (3.2.1-19)	Reduction of heat transfer due to fouling	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements; tanks exposed to treated water (borated) >60 °C (>140 °F) (3.2.1-20)	Cracking due to stress corrosion cracking	Chapter XI.M2, “Water Chemistry” and Chapter XI.M32, “One-Time Inspection”	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Steel (with stainless steel or nickel-alloy cladding) safety injection tank (accumulator) exposed to treated water (borated) >60 °C (>140 °F) (3.2.1-21)	Cracking due to stress corrosion cracking	Chapter XI.M2, “Water Chemistry” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements; tanks exposed to treated water (borated) (3.2.1-22)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry” and Chapter XI.M32, “One-Time Inspection”	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components, containment isolation piping and components internal surfaces) exposed to raw water (3.2.1-23)	Loss of material due to general, pitting, crevice, and micro-biologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-24)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel heat exchanger components, containment isolation piping and components (internal surfaces) exposed to raw water (3.2.1-25)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel heat exchanger tubes exposed to Raw water (3.2.1-26)	Reduction of heat transfer due to fouling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to PWRs
Stainless steel, steel heat exchanger tubes exposed to raw water (3.2.1-27)	Reduction of heat transfer due to fouling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.2.1-28)	Cracking due to stress corrosion cracking	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-29)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components exposed to closed-cycle cooling water (3.2.1-30)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-31)	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Closed Treated Water Systems	Consistent with the GALL Report
Copper alloy heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-32)	Loss of material due to pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Byron and Braidwood
Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water (3.2.1-33)	Reduction of heat transfer due to fouling	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Byron and Braidwood
Copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements, heat exchanger components exposed to closed-cycle cooling water (3.2.1-34)	Loss of material due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to Byron and Braidwood
Gray cast iron motor cooler exposed to treated water (3.2.1-35)	Loss of material due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to Byron and Braidwood
Gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-36)	Loss of material due to selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Gray cast iron piping, piping components, and piping elements exposed to soil (3.2.1-37)	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to Byron and Braidwood
Elastomers, elastomer seals, and components exposed to air – indoor, uncontrolled (external) (3.2.1-38)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to PWRs
Steel containment isolation piping and components (external surfaces) exposed to condensation (external) (3.2.1-39)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Steel ducting, piping, and components (external surfaces), ducting, closure bolting, containment isolation piping and components (external surfaces) exposed to air – indoor, uncontrolled (external) (3.2.1-40)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Steel external surfaces exposed to air – outdoor (external) (3.2.1-41)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Aluminum piping, piping components, and piping elements exposed to air – outdoor (3.2.1-42)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Elastomers, elastomer seals, and components exposed to air – indoor, uncontrolled (internal) (3.2.1-43)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping and components (internal surfaces), ducting and components (internal surfaces) exposed to air – indoor, uncontrolled (internal) (3.2.1-44)	Loss of material due to general corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Steel encapsulation components exposed to air – indoor, uncontrolled (internal) (3.2.1-45)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping and components (internal surfaces) exposed to condensation (internal) (3.2.1-46)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to PWRs
Steel encapsulation components exposed to air with borated water leakage (internal) (3.2.1-47)	Loss of material due to general, pitting, crevice, and boric acid corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements (internal surfaces); tanks exposed to condensation (internal) (3.2.1-48)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-49)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report
Copper alloy, stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-50)	Loss of material due to pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, copper-alloy, stainless steel heat exchanger tubes exposed to lubricating oil (3.2.1-51)	Reduction of heat transfer due to fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report
Steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete (3.2.1-52)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.2.1-53)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Steel; stainless steel underground piping, piping components, and piping elements exposed to air-indoor uncontrolled or condensation (external) (3.2.1-53x)	Loss of material due to general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.2.1-54)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to concrete (3.2.1-55)	None	None, provided (1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557, and (2) plant OE indicates no degradation of the concrete	No, if conditions are met	Consistent with GALL Report and ACI 318	Not applicable to Byron and Braidwood
Aluminum piping, piping components, and piping elements exposed to air – indoor, uncontrolled (internal/external) (3.2.1-56)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Copper-alloy piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external), gas (3.2.1-57)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Copper-alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-58)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Galvanized steel ducting, piping, and components exposed to air – indoor, controlled (external) (3.2.1-59)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass piping elements exposed to air – indoor, uncontrolled (external), lubricating oil, raw water, treated water, treated water (borated), air with borated water leakage, condensation (internal/external), gas, closed-cycle cooling water, air – outdoor (3.2.1-60)	None	None	NA - No AEM or AMP	Consistent with GALL Report	Consistent with the GALL Report
Nickel alloy piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external) (3.2.1-61)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Nickel alloy piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-62)	None	None	NA - No AEM or AMP	Consistent with GALL Report	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, air – indoor, uncontrolled (internal) (3.2.1-63)	None	None	NA - No AEM or AMP	Consistent with GALL Report	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air – indoor, controlled (external), gas (3.2.1-64)	None	None	NA - No AEM or AMP	Consistent with GALL Report	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Insulated steel, Stainless steel, copper alloy, or aluminum, piping, piping components, and tanks exposed to condensation, air-outdoor (3.2.1-69)	Loss of material due to general (steel, and copper alloy only), pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks," (for tanks only)	No	Consistent with GALL Report	Consistent with the GALL Report
Insulated stainless steel, aluminum, or copper alloy (> 15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor (3.2.1-71)	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks," (for tanks only)	No	Consistent with GALL Report	Consistent with GALL Report (see SER Section 3.2.2.2.6

The staff's review of the ESF systems 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 that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.2.2.2, discusses the staff's review of AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.2.2.3, discusses the staff's review of AMR results for components that the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the ESF systems components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.2.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the ESF systems components:

- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- TLAA
- Water Chemistry

LRA Tables 3.2.2-1 through 3.2.2-4 summarize AMRs for the ESFs components 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 GALL Report and for which it does not recommend further evaluation, the staff's audit and review determined if the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noticed for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A–E, indicating how the AMR is consistent with the GALL Report.

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

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

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

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

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect but credits a different AMP. The staff audited these items to confirm 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.

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 confirm 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.

3.2.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.2.1, items 3.2.1-11, 3.2.1-17, 3.2.1-26, 3.2.1-38, 3.2.1-43, 3.2.1-46, and 3.2.1-54, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. The staff reviewed the SRP-LR, confirmed these items only apply to BWRs, and finds that these items are not applicable to BBS, which are PWRs.

For LRA Table 3.2.1, items 3.2.1-10, 3.2.1-12, 3.2.1-14, 3.2.1-16, 3.2.1-21, 3.2.1-23 through 3.2.1-25, 3.2.1-27 through 3.2.1-30, 3.2.1-32 through 3.2.1-37, 3.2.1-39, 3.2.1-41, 3.2.1-42, 3.2.1-45, 3.2.1-52, 3.2.1-53, 3.2.1-53x, 3.2.1-55 through 3.2.1-59, and 3.2.1-61, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at BBS. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.2.1, items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff nonapplicability verification of these items required the review of sources beyond the LRA and UFSAR, and/or the issuance of RAIs.

3.2.2.1.2 Cracking Due to Stress Corrosion Cracking

LRA Table 3.2.1, item 3.2.1-20, addresses SS piping, piping components, piping elements, and tanks exposed to treated borated water greater than 60 °C (140 °F), which will be managed for cracking due to SCC. The GALL Report, as revised by LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," recommends GALL Report AMP XI.M2, "Water Chemistry" and AMP XI.M32, "One-Time Inspection," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M2 recommends using water chemistry control to manage aging by limiting the concentrations of chemical species that cause SCC within the acceptable ranges to minimize the environmental effect on SCC. In addition, GALL Report AMP XI.M32, "One-Time Inspection" confirms the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

During its review of components associated with LRA item 3.2.1-20 for which the applicant cited generic Notes A and C, the staff noticed that the LRA credits the Water Chemistry Program to manage the aging effect. The LRA also credits the One-Time Inspection Program, which will confirm the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

In its review of LRA item 3.2.1-20 and related information, the staff noticed that LRA Tables 3.2.2-3 and 3.2.2-4 address aging management of loss of material in SS restricting orifices using the One-Time Inspection Program and the Water Chemistry Program. However, the staff noticed that the LRA does not address any AMR item to manage aging for feedwater venturi flow meters.

During the audit, the staff also noticed the applicant's OE described in AR 00748581, "Feedwater Venturi Fouling Indication," dated March 12, 2008. The applicant's document (AR 0074881) states that during normal thermal performance monitoring activities, some signs of feedwater flow venturi fouling were observed for Braidwood Unit 2 venturis. The staff further noticed that EPRI Report TR-112118, "Nuclear Feedwater Flow Measurement Application

Guide," July 1999, indicates that venturi flow meters used to calculate feedwater flow rates in nuclear power plants are susceptible to aging degradation such as fouling and loss of material due to erosion and corrosion (including defouling), any of which can cause flow measurement and calculation errors.

In addition, the staff noticed that flow measurement and calculation errors associated with aging degradation of feedwater venturi flow meters could cause safety-related issues such as overpower conditions and could accelerate aging effects of piping and piping components through those overpower conditions. However, the LRA does not describe how the applicant will manage fouling and loss of material for feedwater venturi flow meters.

By letter dated February 26, 2014, the staff issued RAI 3.2.1.20-1 requesting that the applicant describe how the aging effects of fouling and loss of material for feedwater venturi flow meters will be managed, and revise the LRA consistent with the applicant's response. The staff also requested that alternatively, the applicant provide adequate justification why managing of these aging effects is not required.

In its response dated March 28, 2014, the applicant stated that the BBS currently utilize ultrasonic feedwater measurement technology in determining feedwater flow rates for core thermal power calculations. The applicant also stated that the feedwater venturis remain in place as backup flow measurement systems in the event the ultrasonic flow meter systems are not in service and to provide active input into the steam generator level control system. The applicant further indicated that these nonsafety-related venturis do not have a license renewal intended function because they do not provide an input into the reactor trip system and they are not designed to restrict the feedwater flow in the event of a pipe line break.

The applicant also indicated that venturi readings are continuously compared to the outputs of the ultrasonic flow meter systems and these comparisons ensure the accuracy of the venturi flow meters in supporting the non-license-renewal intended function. The applicant further clarified that the applicant performs inspections of the venturis for fouling and loss of material on an 18-month frequency. In addition, the applicant indicated that venturi housings are categorized as piping components in the ESFs and aging effects of these components are managed under the AMR items associated with piping components.

In its review, the staff finds the applicant's response acceptable because the applicant confirmed that (1) ultrasonic flow meters are used to measure and calculate feedwater flow rates for core thermal power calculations instead of the venturi flow meters which are backup systems, (2) the venturi readings are continuously compared to the ultrasonic flow meters to ensure adequate flow measurement and calculation using venturis, and (3) periodic inspections are also performed to detect any fouling and loss of material of the venturis. The staff's concern described in RAI 3.2.1.20-1 is resolved.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.1.6, respectively. The Water Chemistry Program proposes to manage the effects of aging for the SS piping, piping components, piping elements, and tanks through the use of water chemistry monitoring and control of known detrimental contaminants such as chloride, fluorides, DO, and sulfate concentrations below the levels known to result in cracking due to SCC. The One-Time Inspection Program proposes a one-time inspection of the representative sample size (i.e., 20 percent of the population up to a maximum of 25 component inspections) to ensure that no unacceptable aging-related degradation due to SCC is occurring.

Based on its review of components associated with Item 3.2.1-20, for which the applicant cited generic Notes A and C, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC within the acceptable ranges to minimize the environmental effect on SCC and because the One-Time Inspection Program includes a one-time inspection of representative components to confirm the effectiveness of the Water Chemistry Program.

The staff concludes that for LRA item 3.2.1-20, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.3 Cracking Due to Stress Corrosion Cracking

LRA Table 3.2.1, item 3.2.1-71; Table 3.3-1, item 3.3.1-132; and Table 3.4-1, item 3.4.1-63, as revised by letters dated January 13 and May 12, 2014, address insulated SS and aluminum piping, piping components, and piping elements externally exposed to condensation and outdoor air, which will be managed for loss of material (items 3.3.1-132 and 3.4.1-63 only) and cracking.

For the AMR items that cite generic Note E, the LRA credits the One-Time Inspection Program to manage cracking due to SCC. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M36 recommends removing insulation from a sample of components every 10 years during the period of extended operation to allow for examinations for cracking. If the initial inspection does not reveal evidence of cracking, subsequent inspections may consist of examination of the exterior surface of the insulation to detect damage.

The staff's evaluation of the applicant's One-Time Inspection Program is documented in SER Section 3.0.3.1.6. The staff noticed that the applicant's proposal to use the One-Time Inspection Program to manage cracking is similar to the approach of the initial examination in the GALL-recommended AMP XI.M36 described above. An initial inspection will verify whether cracking is present on a sample of component surfaces after insulation is removed using visual inspections for signs of leakage in water-filled piping and visual or NDE techniques to detect cracking of non-water-filled components. If no evidence of cracking is observed, no more inspections for cracking will occur. If evidence of cracking is observed, the One-Time Inspection Program includes an evaluation of the need for followup examinations. The staff also noticed that the applicant's activities to manage for loss of material of the subject insulated piping can provide additional opportunities to discover cracking as well. The applicant is managing loss of material with the External Surface Monitoring of Mechanical Components Program, including an initial bare-metal examination and subsequent examinations every 10 years of either the bare metal or the exterior insulation surface, depending on whether evidence of degradation is detected. Based on its review of components associated with items 3.2.1-71, 3.3.1-132, and 3.4.1-63, for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the One-Time Inspection Program acceptable because the one-time bare-metal inspection of a representative sample of piping, piping components, and piping elements is capable of determining whether cracking is present, and because any indication of cracking will prompt an evaluation of followup examinations to monitor the progression of the aging.

For the AMR items that cite generic Note I, the LRA states that, for insulated SS piping, piping components, and piping elements exposed to condensation in the chemical and volume control and chilled water systems, cracking is not applicable, and no AMP is proposed. Plant-specific Notes 8 (LRA Table 3.3.2-2) and 2 (LRA Table 3.3.2-3) state that "[t]he insulating materials for this component do not contain leachable halides" and "[e]xternal sources of halides are not a significant contributor to the occurrence of SCC as the component is located indoors." In its letter dated January 13, 2014, the applicant also stated that "[a] review of the insulation specification and procedures indicates that insulating materials with leachable halides are not used at Byron and Braidwood on components within the scope of this response." The staff reviewed the associated items in the LRA to confirm that this aging effect is not applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable because SCC is not expected to occur on the exterior surfaces of insulated SS components that are not exposed to halides in the insulation or are located indoors (i.e., shielded from airborne halides that may be in outdoor air).

The staff concludes that, for LRA items 3.2.1-71, 3.3.1-132, and 3.4.1-63, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.2.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the ESF components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to cladding breach
- loss of material due to pitting and crevice corrosion
- loss of material due to erosion
- loss of material due to general corrosion and fouling that leads to corrosion
- cracking due to SCC
- QA for aging management of nonsafety-related components

3.2.2.2.1 Cumulative Fatigue Damage

LRA Section 3.2.2.2.1 is associated with LRA Table 3.2.1 item 3.2.1-1 that addresses steel and SS piping, piping components, and piping elements exposed to treated water (borated) in the engineered-safety systems and being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3 and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Sections 4.3 and 4.7.

The staff reviewed LRA Section 3.2.2.2.1 against the criteria in SRP-LR Section 3.2.2.2.1 which states that cumulative fatigue damage of steel and SS piping, piping components, and piping elements in the engineered-safety systems is a TLAA, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements of 10 CFR 54.21(c). The staff reviewed the applicant's AMR line items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR, for managing cumulative fatigue damage in steel and SS piping, piping components, and piping elements.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.2.2.2.1 criteria. For those line items that apply to LRA Section 3.2.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAA for these components.

3.2.2.2.2 Loss of Material Due to Cladding Breach

LRA Section 3.2.2.2.2, associated with LRA Table 3.2.1, item 3.2.1-2, addresses loss of material due to cladding breach in steel with SS cladding charging pump casings exposed to treated borated water. The staff noticed that this item is associated with NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks." The applicant stated that this item is not applicable because there are no steel with SS cladding charging pump casings exposed to treated borated water in the ESFs systems. The staff evaluated the applicant's claim and finds it acceptable because a review of LRA Section 3.2 and UFSAR Table 6.3-4 confirmed that the charging pumps are constructed of SS rather than steel with SS cladding; consequently, loss of material due to boric acid corrosion is not an applicable aging effect.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

Item 1. LRA Section 3.2.2.2.2, associated with LRA Table 3.2.1, item 3.2.1-3, addresses loss of material due to pitting and crevice corrosion in SS partially-encased tanks with a breached moisture barrier exposed to raw water. The criteria in SRP-LR Section 3.2.2.2.3 item 1 states that a plant-specific AMP is to be evaluated for pitting and crevice corrosion of the tank bottom because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering. The applicant stated that this item is not applicable because "[t]here are no partially encased stainless steel tanks with perimeter seals that protect the external embedded stainless surfaces from exposure to raw water in the Engineered Safety Features systems." The staff evaluated the applicant's claim and finds it acceptable because based on its review of the UFSAR and a walkdown conducted during the AMP audit, the staff confirmed that there are no SS partially-encased tanks in the ESF systems.

Item 2. LRA Section 3.2.2.2.3, associated with LRA Table 3.2.1, item 3.2.1-4, addresses SS piping, piping components, piping elements, and tanks exposed to outdoor air. The criteria in SRP-LR Section 3.2.2.2.3, item 2, states that loss of material due to pitting and crevice corrosion could occur for SS piping, piping components, piping elements, and tanks exposed to outdoor air. In a letter dated January 13, 2014, the applicant stated that this item is not applicable because the subject components are insulated at BBS. The insulated SS components are associated with LRA Table 3.2.1, item 3.2.1-69. The staff evaluated the applicant's claim and finds it acceptable because the staff's review of LRA Sections 2.3.2 and 3.2 and the UFSAR did not find evidence of uninsulated SS components exposed to outdoor air in the ESFs systems. In addition, the staff confirmed that the applicant evaluated loss of material of insulated SS components with item 3.2.1-69, as documented in SER Section 3.2.2.1.

3.2.2.2.4 Loss of Material Due to Erosion

LRA Section 3.2.2.2.4 is associated with LRA Table 3.2.1, item 3.2.1-5, and addresses SS orifices in minimum flow piping for high-pressure safety injection (HPSI) pumps that are exposed to treated borated water. The applicant will implement the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage loss of material due to erosion for components associated with this item in the CVCS. The staff notes that the erosion issue discussed in the GALL Report was based on the length of time that the orifice experiences flow and was not based on any chemistry control concerns. The criteria in SRP-LR Section 3.2.2.2.4 state that loss of material due to erosion could occur in SS orifices of minimum flow recirculation piping. The SRP-LR recommends a plant-specific AMP be evaluated for erosion of the orifices due to extended use of the centrifugal HPSI pumps for normal charging. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will perform a one-time inspection of one orifice on each unit associated with the centrifugal charging pump minimum flow recirculation piping prior to the period of extended operation.

The staff's evaluation of the applicant's One-Time Inspection Program is documented in SER Section 3.0.3.1.6. The staff noticed that the One-Time Inspection Program can be used to demonstrate that either the aging effect does not occur or that the aging effect is occurring very slowly and does not affect the component's intended function. The staff also noticed that the One-Time Inspection Program manages loss of material due to erosion with visual or volumetric inspections to detect changes in surface condition or loss of wall thickness. In its review of components associated with item 3.2.1-5, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage the effects of aging using the One-Time Inspection Program is acceptable because an inspection of one orifice on each unit constitutes a sufficient number of inspections to provide reasonable assurance that loss of material due to erosion for the centrifugal charging pump minimum flow recirculation orifices will be adequately managed.

3.2.2.2.5 Loss of Material Due to General Corrosion and Fouling That Leads to Corrosion

LRA Section 3.2.2.2.5, associated with LRA Table 3.2.1, item 3.2.1-6, addresses loss of material due to general corrosion and fouling that leads to corrosion in steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air - indoor uncontrolled. The applicant stated that this item is not applicable because it applies to BWRs only. The staff evaluated the applicant's claim and finds it acceptable because the staff confirmed that this item is associated only with BWRs.

3.2.2.2.6 Cracking Due to Stress Corrosion Cracking

LRA Section 3.2.2.2.6, associated with LRA Table 3.2.1, item 3.2.1-7, addresses SS piping, piping components, piping elements, and tanks exposed to outdoor air. The criteria in SRP-LR Section 3.2.2.2.6 states that cracking due to SCC could occur for SS piping, piping components, piping elements, and tanks exposed to outdoor air. In a letter dated January 13, 2014, the applicant stated that this item is not applicable because the subject components are insulated at the BBS. The insulated SS components are associated with LRA Table 3.2.1, item 3.2.1-71. The staff evaluated the applicant's claim and finds it acceptable because the staff's review of LRA Sections 2.3.2 and 3.2 and the UFSAR did not find evidence of uninsulated SS components exposed to outdoor air in the ESFs systems. In addition, the staff confirmed that the applicant evaluated cracking of insulated SS components with item 3.2.1-71, as documented in SER Section 3.2.2.1.3.

3.2.2.2.7 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.2.2.2.8 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of OE of AMPs.

3.2.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-4, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.2.2-1 through 3.2.2-4, the applicant indicated, via Notes F through J, which the combination of component type, material, environment, and AERM does not correspond to an AMR item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR 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 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. The staff's evaluation is discussed in the following sections.

3.2.2.3.1 Combustible Gas Control System—Summary of Aging Management Evaluation—LRA Table 3.2.2-1

Carbon Steel Components Exposed to Air with Borated Water Leakage. In LRA Tables 3.2.2-1, 3.2.2-2, 3.4.2-1, 3.5.2-3, and 3.5.2-15, the applicant did not include AMR items for loss of material due to general, pitting, and crevice corrosion for several carbon steel components exposed to air with borated water leakage.

The staff reviewed the associated items in the LRA to confirm that loss of material due to general, pitting, and crevice corrosion is not applicable for the subject components. The staff noticed that LRA Table 3.0-1 states that the air with borated water leakage environment is similar to the air-indoor uncontrolled environment, which is described as an environment where the surfaces of components may be wetted, but only rarely. The staff also noticed that the GALL Report cites loss of material due to general, pitting, and crevice corrosion as an aging effect for carbon steel exposed to uncontrolled indoor air. Therefore, by letter dated February 6, 2014, the staff issued RAI 3.2.2-1 requesting that the applicant justify why loss of material due to general, pitting, and crevice corrosion is not applicable to the subject components.

In its response dated February 27, 2014, the applicant stated that the aging effect for loss of material due to general corrosion should have been included for the subject components. Therefore, the applicant revised the LRA to add AMR items for loss of material due to general corrosion for components associated with LRA items 3.2.1-40 and 3.4.1-34, loss of material due to general and pitting corrosion for components associated with LRA item 3.5.1-91, and loss of material due to general, pitting, and crevice corrosion for components associated with LRA item 3.5.1-80. For these new AMR items, the applicant citied generic Notes A or D.

The staff finds the applicant's response acceptable because the applicant appropriately added AMR items that address loss of material of steel components that are exposed to uncontrolled indoor air (condensation can occur, but only rarely). The staff's evaluations of the individual AMR line items that are associated with this RAI response are documented in the appropriate SER sections for those line items. The staff's concern described in RAI 3.2.2-1 is resolved.

On the basis of its review, the staff concludes for items in LRA Table 3.2.2-1 with no AERMs that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.2 Containment Spray System—Summary of Aging Management Evaluation—LRA Table 3.2.2-2

Carbon Steel Components Exposed to Air with Borated Water Leakage. The staff's evaluation for carbon steel components exposed to air with borated water leakage, for which the applicant did not include AMR items for loss of material due to general, pitting, and crevice corrosion, is documented in SER Section 3.2.2.3.1.

On the basis of its review, the staff concludes for items in LRA Table 3.2.2-2 with no AERMs that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.3 Residual Heat Removal 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 RHR system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the RHR system component groups are consistent with the GALL Report.

3.2.2.3.4 Safety Injection System—Summary of Aging Management Evaluation—LRA Table 3.2.2-4

Carbon Steel Electric Heaters Exposed to Treated Borated Water. In LRA Table 3.2.2-4, the applicant stated that carbon steel electric heaters associated with the RWST at Braidwood exposed internally to treated borated water will be managed for loss of material by the Water

Chemistry and One-Time Inspection Programs. The AMR items cite generic Note G. However, in letter dated May 5, 2014, the applicant deleted the subject AMR items because the carbon steel heater shells were replaced with SS in 2013. The applicant associated the new SS heater shells with existing AMR line items for the Byron SS electric heaters, which reference LRA item 3.2.1-22. The staff's evaluation of components associated with LRA item 3.2.1-22 is documented in SER Section 3.2.2.1.

Nickel Alloy Electric Heaters Externally Exposed to Treated Borated Water. In LRA Table 3.2.2-4, the applicant stated that nickel alloy electric heaters (associated with the RWSTs) externally exposed to treated borated water will be managed for loss of material by the Water Chemistry and One-Time Inspection Programs. The AMR item cites generic Note G and plant-specific Note 1, which states that the Water Chemistry and One-Time Inspection Programs are used to manage the aging effects for this component, material, and environment combination.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff reviewed: "ASM Specialty Handbook - Nickel, Cobalt, and Their Alloys," which states nickel alloys, such as alloy 600 from which the elements are constructed, are "highly resistant to general corrosion and SCC but can be attacked at high caustic concentrations and temperatures." In addition, SCC has also been found to occur in environments with elevated levels of halides and sulfur species. As documented in SER Section 3.0.3.1.1, the staff found that the applicant monitors the RWST in accordance with EPRI 1014986, "PWR Primary Water Chemistry Guidelines," Revision 6. These guidelines include the monitoring of chlorides, fluorides, sulfates, and sodium (as an indicator for the presence of (caustic) sodium hydroxide). During the audit, the staff confirmed that the applicant monitors these parameters monthly. Therefore, cracking is not a likely aging effect. The staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.1 and 3.0.3.1.6, respectively. The applicant's Water Chemistry Program manages loss of material, cracking, and reduction in heat transfer in components exposed to a treated water environment through periodic monitoring and control of water chemistry. The One-Time Inspection Program performs focused inspections of components susceptible to certain aging effects to verify the effectiveness of the water chemistry controls.

The staff finds the applicant's proposal to manage loss of material using the Water Chemistry and One-Time Inspection Programs acceptable because maintaining proper primary water chemistry will control certain parameters known to contribute to corrosion and because a one-time inspection of components in low flow and stagnant areas, such as the electric heaters associated with the RWSTs, will confirm the effectiveness of the Water Chemistry Program (i.e., that age-related degradation does not occur).

Carbon Steel Oil Reservoirs with Internal Coating or Lining Exposed to Lubricating Oil. In LRA Table 3.2.2-4, as revised by letter dated January 13, 2014, the applicant stated that carbon steel safety injection pump oil reservoirs with internal coating or lining exposed to lubricating oil will be managed for loss of coating integrity by the Lubricating Oil Analysis program. The AMR item cites generic Note H.

The staff's evaluation of the applicant's Lubricating Oil Analysis program is documented in SER Section 3.0.3.1.12. In addition, the staff's evaluation of how the applicant is going to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage for coatings that have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks) is documented in SER Section 3.0.3.3.1. The staff finds the applicant's proposal to manage loss of coating integrity using the Lubricating Oil Analysis program acceptable because the program includes oil sampling and quarterly monitoring of the differential pressure across the safety injection pump's lube oil filter, which can detect particulates indicative of degraded internal coatings.

On the basis of its review, the staff concludes for items in LRA Table 3.2.2-4 with no AERMs that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report and 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).

3.2.3 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 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 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 following systems:

- auxiliary building ventilation system
- chemical & 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 generator & auxiliaries system
- fire protection system
- fresh water system
- fuel handling & fuel storage system
- fuel oil system
- heating water and heating steam system
- nonradioactive drain system
- radiation monitoring system
- radioactive drain system
- radwaste system
- sampling system

- service water system
- spent fuel cooling 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 Evaluations for the 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 OE 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 OE included a review of the GALL Report and OE issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

Table 3.3-1 summarizes the staff’s evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel cranes: structural girders exposed to air – indoor, uncontrolled (external) (3.3.1-1)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation for structural girders of cranes that fall within the scope of 10 CFR 54 (SRP-LR Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1)).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.3.2.2.1)
Stainless steel, steel heat exchanger components and tubes, piping, piping components, and piping elements exposed to treated borated water, air - indoor, uncontrolled, treated water (3.3.1-2)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation. See the SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.3.2.2.1)
Stainless steel heat exchanger components, nonregenerative exposed to treated borated water >60 °C (>140 °F) (3.3.1-3)	Cracking due to SCC; cyclic loading	Chapter XI.M2, "Water Chemistry." The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	Yes	Water Chemistry Program, One-Time Inspection Program, and Closed Treated Water Systems Program	Consistent with the GALL Report (see SER Section 3.3.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor (3.3.1-4)	Cracking due to SCC	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.3.2.2.3)
Steel (with stainless steel or nickel-alloy cladding) pump casings exposed to treated borated water (3.3.1-5)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.3.2.2.4)
Stainless steel piping, piping components, and piping elements; tanks exposed to air–outdoor (3.3.1-6)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Section 3.3.2.2.5)
Stainless steel high-pressure pump, casing exposed to treated borated water (3.3.1-7)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Stainless steel heat exchanger components and tubes exposed to treated borated water >60 °C (>140 °F) (3.3.1-8)	Cracking due to cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Steel, aluminum, copper-alloy (>15% Zn or >8% Al) external surfaces, piping, piping components, and piping elements, bolting exposed to air with borated water leakage (3.3.1-9)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, high-strength closure bolting exposed to air with steam or water leakage (3.3.1-10)	Cracking due to SCC; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood
Steel, high-strength high-pressure pump, closure bolting exposed to air with steam or water leakage (3.3.1-11)	Cracking due to SCC; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood
Steel; stainless steel closure bolting, bolting exposed to condensation, air – indoor, uncontrolled (external), air – outdoor (external) (3.3.1-12)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program	Consistent with the GALL Report
Steel closure bolting exposed to air with steam or water leakage (3.3.1-13)	Loss of material due to general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood
Steel, stainless steel bolting exposed to soil (3.3.1-14)	Loss of preload	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program	Consistent with the GALL Report
Steel; stainless steel, copper-alloy, nickel alloy, stainless steel closure bolting, bolting exposed to air – indoor, uncontrolled (external), any environment, air – outdoor (external), raw water, treated borated water, fuel oil, treated water (3.3.1-15)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program and Structures Monitoring Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.3.1-16)	Cracking due to SCC, intergranular SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M25, "BWR Reactor Water Cleanup System"	No	Not applicable	Not applicable to PWRs
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-17)	Reduction of heat transfer due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Stainless steel high-pressure pump, casing, Piping, piping components, and piping elements exposed to treated borated water >60 °C (>140 °F), sodium pentaborate solution >60 °C (>140 °F) (3.3.1-18)	Cracking due to SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel regenerative heat exchanger components exposed to treated water >60 °C (>140 °F) (3.3.1-19)	Cracking due to SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel, stainless steel; steel with stainless steel cladding heat exchanger components exposed to treated borated water >60 °C (>140 °F), treated water >60 °C (>140 °F) (3.3.1-20)	Cracking due to SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	One-Time Inspection Program and Water Chemistry Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to treated water (3.3.1-21)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, and piping elements exposed to treated water (3.3.1-22)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to PWRs
Aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-23)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to Byron and Braidwood
Aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-24)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to PWRs
Stainless steel, stainless steel; steel with stainless steel cladding, aluminum piping, piping components, and piping elements, heat exchanger components exposed to treated water, sodium pentaborate solution (3.3.1-25)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to PWRs
Steel (with elastomer lining), steel (with elastomer lining or stainless steel cladding) piping, piping components, and piping elements exposed to treated water (3.3.1-26)	Loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation)	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-27)	Reduction of heat transfer due to fouling	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel (with stainless steel or nickel-alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components, and piping elements, piping, piping components, and piping elements; tanks exposed treated water >60 °C (>140 °F), treated borated water >60 °C (>140 °F) (3.3.1-28)	Cracking due to SCC	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry Program	Consistent with the GALL Report
Steel (with stainless steel cladding); stainless steel piping, piping components, and piping elements exposed to treated borated water (3.3.1-29)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry Program	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-30)	Changes in material properties due to aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Byron and Braidwood
Fiberglass, HDPE piping, piping components, and piping elements exposed to raw water (internal) (3.3.1-30x)	Cracking, blistering, change in color due to water absorption	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Byron and Braidwood
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-31)	Cracking due to settling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to raw water (3.3.1-32)	Cracking due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Byron and Braidwood
Elastomer seals and components exposed to raw water (3.3.1-32x)	Hardening and loss of strength due to elastomer degradation; loss of material due to erosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-33)	Loss of material due to abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Byron and Braidwood
Nickel alloy, copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-34)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-35)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-36)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Steel (with coating or lining) piping, piping components, and piping elements exposed to raw water (3.3.1-37)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion; fouling that leads to corrosion; lining/coating degradation	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Copper alloy, steel heat exchanger components exposed to raw water (3.3.1-38)	Loss of material due to general, pitting, crevice, galvanic, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program and ASME Section XI, Subsection IWF Program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-39)	Loss of material due to pitting and crevice corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-40)	Loss of material due to pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program and ASME Section XI, Subsection IWF Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-41)	Loss of material due to pitting, crevice, and micro-biologically influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water (3.3.1-42)	Reduction of heat transfer due to fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-43)	Cracking due to SCC	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-44)	Cracking due to SCC	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping, piping components, and piping elements; tanks exposed to closed-cycle cooling water (3.3.1-45)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Steel, copper-alloy heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-46)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1-47)	Loss of material due to microbi-ologically influenced corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable for PWRs
Aluminum piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-48)	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-49)	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Consistent with the GALL Report
Stainless steel, copper-alloy, steel heat exchanger tubes exposed to closed-cycle cooling water (3.3.1-50)	Reduction of heat transfer due to fouling	Chapter XI.M21A, “Closed Treated Water Systems”	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Boraflex spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water (3.3.1-51)	Reduction of neutron-absorbing capacity due to boraflex degradation	Chapter XI.M22, “Boraflex Monitoring”	No	Not applicable	Not applicable to Byron and Braidwood
Steel cranes: rails and structural girders exposed to air – indoor, uncontrolled (external) (3.3.1-52)	Loss of material due to general corrosion	Chapter XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel cranes - rails exposed to air – indoor, uncontrolled (external) (3.3.1-53)	Loss of material due to wear	Chapter XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to condensation (3.3.1-54)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M24, “Compressed Air Monitoring”	No	Compressed Air Monitoring program Exceptions apply to Compressed Air Monitoring program	Consistent with the GALL Report
Steel piping, piping components, and piping elements: compressed air system exposed to condensation (internal) (3.3.1-55)	Loss of material due to general and pitting corrosion	Chapter XI.M24, “Compressed Air Monitoring”	No	Compressed Air Monitoring program Exceptions apply to Compressed Air Monitoring program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-56)	Loss of material due to pitting and crevice corrosion	Chapter XI.M24, “Compressed Air Monitoring”	No	Compressed Air Monitoring program Exceptions apply to Compressed Air Monitoring program	Consistent with the GALL Report
Elastomers fire barrier penetration seals exposed to air - indoor, uncontrolled, air – outdoor (3.3.1-57)	Increased hardness; shrinkage; loss of strength due to weathering	Chapter XI.M26, “Fire Protection”	No	Fire Protection program	Consistent with the GALL Report
Steel halon/CO_2 fire suppression system piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external) (3.3.1-58)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M26, “Fire Protection”	No	Fire Protection program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel fire rated doors exposed to air - indoor, uncontrolled, air – outdoor (3.3.1-59)	Loss of material due to wear	Chapter XI.M26, “Fire Protection”	No	Fire Protection program	Consistent with the GALL Report
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air - indoor, uncontrolled (3.3.1-60)	Concrete cracking and spalling due to aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, “Fire Protection,” and Chapter XI.S6, “Structures Monitoring”	No	Fire Protection program and Structures Monitoring program	Consistent with the GALL Report
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air – outdoor (3.3.1-61)	Cracking, loss of material due to freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, “Fire Protection,” and Chapter XI.S6, “Structures Monitoring”	No	Fire Protection program and Structures Monitoring program	Consistent with the GALL Report
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air - indoor, uncontrolled, air – outdoor (3.3.1-62)	Loss of material due to corrosion of embedded steel	Chapter XI.M26, “Fire Protection,” and Chapter XI.S6, “Structures Monitoring”	No	Fire Protection program and Structures Monitoring program	Consistent with the GALL Report
Steel fire hydrants exposed to air – outdoor (3.3.1-63)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M27, “Fire Water System”	No	Fire Water System program	Consistent with the GALL Report
Steel, copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-64)	Loss of material due to general, pitting, crevice, and micro-biologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M27, “Fire Water System”	No	Fire Water System program	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to raw water (3.3.1-65)	Loss of material due to pitting and crevice corrosion	Chapter XI.M27, “Fire Water System”	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-66)	Loss of material due to pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M27, “Fire Water System”	No	Fire Water System program	Consistent with the GALL Report
Steel tanks exposed to air – outdoor (external) (3.3.1-67)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, “Aboveground Metallic Tanks”	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1-68)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M30, “Fuel Oil Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to Byron and Braidwood
Copper alloy piping, piping components, and piping elements exposed to fuel oil (3.3.1-69)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M30, “Fuel Oil Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Fuel Oil Chemistry program and One-Time Inspection Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements; tanks exposed to fuel oil (3.3.1-70)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M30, “Fuel Oil Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Fuel Oil Chemistry program and One-Time Inspection Program	Consistent with the GALL Report
Stainless steel, aluminum piping, piping components, and piping elements exposed to fuel oil (3.3.1-71)	Loss of material due to pitting, crevice, and micro-biologically influenced corrosion	Chapter XI.M30, “Fuel Oil Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Fuel Oil Chemistry program and One-Time Inspection Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Gray cast iron, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements, heat exchanger components exposed to treated water, closed-cycle cooling water, Soil, Raw water (3.3.1-72)	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching program	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to air – outdoor (3.3.1-73)	Changes in material properties due to aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Concrete; cementitious material piping, piping components, and piping elements exposed to air – outdoor (3.3.1-74)	Cracking due to settling	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to air – outdoor (3.3.1-75)	Cracking due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Elastomers, elastomer seals and components exposed to air – indoor, uncontrolled (Internal/External) (3.3.1-76)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete; cementitious material piping, piping components, and piping elements exposed to air – outdoor (3.3.1-77)	Loss of material due to abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping and components (external surfaces), ducting and components (external surfaces), ducting; closure bolting exposed to air – indoor, uncontrolled (external), air – indoor, uncontrolled (external), air – outdoor (external), condensation (external) (3.3.1-78)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to condensation (external) (3.3.1-79)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Byron and Braidwood
Steel heat exchanger components, piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external), air – outdoor (external) (3.3.1-80)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report
Copper alloy, aluminum piping, piping components, and piping elements exposed to air – outdoor (external), air – outdoor (3.3.1-81)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomers, elastomer: seals and components exposed to air – indoor, uncontrolled (external) (3.3.1-82)	Loss of material due to wear	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-83)	Cracking due to SCC	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Elastomers, elastomer seals and components exposed to closed-cycle cooling water (3.3.1-85)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	Not applicable to Byron and Braidwood
Elastomers, linings, elastomer: seals and components exposed to treated borated water, treated water, raw water (3.3.1-86)	Hardening and loss of strength due to elastomer degradation	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not applicable	Not applicable to Byron and Braidwood
Steel; stainless steel piping, piping components, and piping elements, piping, piping components, and piping elements, diesel engine exhaust exposed to raw water (potable), diesel exhaust (3.3.1-88)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Steel, copper-alloy piping, piping components, and piping elements exposed to moist air or condensation (Internal) (3.3.1-89)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel ducting and components (internal surfaces) exposed to condensation (internal) (3.3.1-90)	Loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbi-ologically influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and Fire Protection program	Consistent with the GALL Report
Steel piping, piping components, and piping elements; tanks exposed to waste water (3.3.1-91)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-92)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to raw water (potable) (3.3.1-93)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Stainless steel ducting and components exposed to condensation (3.3.1-94)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy, stainless steel, nickel alloy, steel piping, piping components, and piping elements, heat exchanger components, piping, piping components, and piping elements; tanks exposed to waste water, condensation (internal) (3.3.1-95)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Elastomers, elastomer: seals and components exposed to air – indoor, uncontrolled (internal) (3.3.1-96)	Loss of material due to wear	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping, piping components, and piping elements, reactor coolant pump oil collection system: tanks, reactor coolant pump oil collection system: piping, tubing, valve bodies exposed to lubricating oil (3.3.1-97)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program, One-Time Inspection Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Steel heat exchanger components exposed to lubricating oil (3.3.1-98)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy, aluminum Piping, piping components, and piping elements exposed to lubricating oil (3.3.1-99)	Loss of material due to pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program, One-Time Inspection Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-100)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis program, One-Time Inspection Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Aluminum heat exchanger tubes exposed to lubricating oil (3.3.1-101)	Reduction of heat transfer due to fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood
Boral; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water (3.3.1-102)	Reduction of neutron-absorb ing capacity; change in dimensions and loss of material due to effects of SFP environment	Chapter XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Monitoring of Neutron-Absor bing Materials other than Boraflex program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to soil or concrete (3.3.1-103)	Cracking due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
HDPE, fiberglass piping, piping components, and piping elements exposed to soil or concrete (3.3.1-104)	Cracking, blistering, change in color due to water absorption	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report
Concrete cylinder piping, asbestos cement pipe piping, piping components, and piping elements exposed to soil or concrete (3.3.1-105)	Cracking, spalling, corrosion of rebar due to exposure of rebar	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete (3.3.1-106)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.3.1-107)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Titanium, super austenitic, aluminum, copper Alloy, stainless steel piping, piping components, and piping elements, bolting exposed to soil or concrete (3.3.1-108)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Not applicable	Not applicable to Byron and Braidwood
Steel bolting exposed to soil or concrete (3.3.1-109)	Loss of material due to general, pitting and crevice corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report
Underground aluminum, copper alloy, stainless steel and steel piping, piping components, and piping elements (3.3.1-109x)	Loss of material due to general (steel only), pitting and crevice corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.3.1-110)	Cracking due to SCC	Chapter XI.M7, “BWR Stress Corrosion Cracking,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to PWRs
Steel structural steel exposed to air – indoor, uncontrolled (external) (3.3.1-111)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to concrete (3.3.1-112)	None	None, provided (1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557, and (2) plant OE indicates no degradation of the concrete	No, if conditions are met	Consistent with the GALL Report	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to air – dry (internal/external), air – indoor, uncontrolled (internal/external), air – indoor, controlled (external), gas (3.3.1-113)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to air – indoor, uncontrolled (internal/external), air – dry, gas (3.3.1-114)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Copper alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-115)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Galvanized steel piping, piping components, and piping elements exposed to air - indoor, uncontrolled (3.3.1-116)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Glass piping elements exposed to air – indoor, uncontrolled (external), lubricating oil, closed-cycle cooling water, air – outdoor, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation (internal/external) gas (3.3.1-117)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Nickel alloy piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external) (3.3.1-118)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Nickel alloy, PVC, glass Piping, piping components, and piping elements exposed to air with borated water leakage, air – indoor, uncontrolled, condensation (internal), waste water (3.3.1-119)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to air – indoor, uncontrolled (internal/external), air – indoor, uncontrolled (external), air with borated water leakage, concrete, air – dry, gas (3.3.1-120)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air – indoor, controlled (external), air – dry, gas (3.3.1-121)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Titanium heat exchanger components, piping, piping components, and piping elements exposed to air – indoor, uncontrolled or air – outdoor (3.3.1-122)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Titanium (ASTM grades 1,2, 7, 11, or 12 that contains > 5% aluminum or more than 0.20% oxygen or any amount of tin) heat exchanger components other than tubes, piping, piping components, and piping elements exposed to raw water (3.3.1-123)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel (with stainless steel or nickel-alloy cladding), spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components, and piping elements; exposed to treated water >60 °C (>140 °F), treated borated water >60 °C (>140 °F) (3.3.1-124)	Cracking due to SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood
Steel (with stainless steel cladding), stainless steel spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components, and piping elements; exposed to treated water, treated borated water (3.3.1-125)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report
Insulated steel, stainless steel, copper alloy, aluminum, or copper alloy (>15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor (3.3.1-132)	Loss of material due to general (steel, and copper alloy only), pitting, and crevice corrosion; cracking due to stress corrosion cracking (aluminum, stainless steel and copper alloy (>15% Zn) only)	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks" (for tanks only)	No	One-Time Inspection Program	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 that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.3.2.2, discusses the staff's review of AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.3.2.3, discusses the staff's review of AMR results for components that the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.3.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the auxiliary systems components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping
- Closed Treated Water Systems
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- 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
- Masonry Walls
- Monitoring of Neutron-Absorbing Materials Other than Boraflex
- One-Time Inspection
- Open-Cycle Cooling Water System
- Selective Leaching
- Structures Monitoring
- TLAA
- Water Chemistry

LRA Tables 3.3.2-1 through 3.3.2-23 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 claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if 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 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–E, which indicate how the AMR was consistent with the GALL Report.

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

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these AMR items to confirm 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 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. Note C 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 AMR items to confirm consistency with the GALL Report. The staff also determined whether the AMR 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 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 AMR items to confirm consistency with the GALL Report and confirmed whether the AMR 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. 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these AMR items to confirm 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 did not repeat its review of the matters described in the GALL Report; however, it did confirm 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.

3.3.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.3.1, items 3.3.1-16, 3.3.1-21, 3.3.1-22, 3.3.1-24, 3.3.1-25, 3.3.1-27, and 3.3.1-110, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. The staff reviewed the SRP-LR, confirmed these items only apply to BWRs, and finds that these items are not applicable to BBS, which are PWRs.

For LRA Table 3.3.1, items 3.3.1-10, 3.3.1-11, 3.3.1-13, 3.3.1-18, 3.3.1-23, 3.3.1-26, 3.3.1-30, 3.3.1-30x, 3.3.1-31 through 3.3.1-33, 3.3.1-44, 3.3.1-48, 3.3.1-51, 3.3.1-65, 3.3.1-67, 3.3.1-68, 3.3.1-73 through 3.3.1-75, 3.3.1-77, 3.3.1-79, 3.3.1-85, 3.3.1-86, 3.3.1-101, 3.3.1-103, 3.3.1-107, 3.3.1-108, 3.3.1-118, and 3.3.1-124, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at BBS. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.3.1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff nonapplicability verification of these items required the review of sources beyond the LRA and UFSAR, and/or the issuance of RAIs.

LRA Table 3.3.1, item 3.3.1-19 addresses SS regenerative heat exchanger components exposed to treated water. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection," to manage cracking due to SCC for this component group. The applicant stated that this item is not applicable because these components are addressed through item 3.3.1-20. The staff finds the applicant's approach acceptable because the alternate item includes the same material, aging effect, environment, and AMPs.

LRA Table 3.3.1, item 3.3.1-39 addresses SS piping exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System" to manage loss of material due to pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because these components are addressed through item 3.3.1-40. The staff finds the applicant's approach acceptable because the alternate item includes the same material, aging effect, environment, AMP.

LRA Table 3.3.1, item 3.3.1-47 addresses SS and steel with SS cladding heat exchanger components exposed to closed-cycle cooling water. The GALL Report recommends GALL Report AMP XI.21A, "Closed Treated Water Systems," to manage loss of material due to MIC for this component group. The applicant stated that this item is not applicable because it is applicable to BWR plants only. Although SRP-LR Table 3.3-1, item 47 does not state that MIC is applicable to PWR plants, the staff noticed that EPRI 1007820, "Closed Cooling Water Chemistry Guideline, Revision 1," states that microbiological organisms can be found in virtually all closed cooling water systems. As documented in the staff's Audit Report of the Closed Treated Water Systems Program, the staff also noticed that the applicant is monitoring for microbiological activity in its closed treated water systems and that the program has guidance for when MIC activity measurements fall outside of goal ranges. The staff further noticed that the LRA contains AMR items for SS and carbon steel clad with SS heat exchanger components exposed to closed-cycle cooling water that are managed for loss of material due to pitting and crevice corrosion with the Closed Treated Water Systems Program, which includes visual inspections at least once every 10 years. As a result, the staff finds the applicant's claim acceptable because, although the SRP-LR associates this item only with BWR plants, the applicant is appropriately managing loss of material due to MIC for the subject components through water chemistry monitoring for MIC activity and visual inspections for corrosion in the Closed Treated Water Systems Program, consistent with GALL Report guidance.

LRA Table 3.3.1, item 3.3.1-96 addresses elastomeric seals and components exposed to air – indoor, uncontrolled (Internal). The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage loss of material due to wear for this component group. The applicant stated that this item is not applicable because, "[t]he internal environment of elastomer seals and components in the Auxiliary Building Ventilation System, containment Ventilation System, and Control Area Ventilation System is considered to be condensation. Loss of material of these components is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program." The staff evaluated the applicant's claim and finds it acceptable because: (a) based on a review of LRA Section 3.3, the only internal environments cited for elastomeric components are condensation and raw water; therefore, there are no elastomeric seals and components exposed to air – indoor, uncontrolled (Internal); and (b) a review of the UFSAR did not reveal any other elastomeric seals than cited in the applicant's above statement.

3.3.2.1.2 Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-Loosening (Byron only)

LRA Table 3.3.1, item 3.3.1-15 addresses steel, copper-alloy, and SS bolting exposed to air-indoor uncontrolled, air-outdoor, air with borated water leakage, condensation, and raw water, which will be managed for loss of preload due to thermal effects, gasket creep, and self-loosening. For the AMR item that cites generic Note E, the LRA credits the Structures Monitoring program to manage the aging effect for SS bolting that is exposed to raw water at Byron Station and is associated with supports for the EDGs, heating, ventilation, and air conditioning (HVAC) system components, and other miscellaneous mechanical equipment. The staff noticed that, although the applicant cited generic Note E for this item, the use of the Structures Monitoring program to manage the aging of the subject structural bolting is consistent with GALL Report guidance.

The staff noticed that the LRA does not contain an AMR item for the loss of material aging effect for the subject bolting. The GALL Report does not contain a specific AMR item for SS structural bolting exposed to raw water; however, it does state that loss of material due to pitting, crevice, and microbiologically influenced corrosion is an applicable aging effect for other SS components in raw water environments. Therefore, by letter dated February 6, 2014, the staff issued RAI 3.5.2-1 requesting that the applicant either provide the technical basis to justify why loss of material is not an applicable aging effect or provide an AMR item that describes how loss of material will be managed.

In its response dated February 27, 2014, the applicant stated that it should have included an AMR item to address the loss of material aging effect for the subject bolting. The applicant stated that loss of material will be managed by the Structures Monitoring program, which includes visual inspections performed at least once every 5 years.

The staff finds the applicant's response acceptable because it added an AMR item to LRA Table 3.5.2-3 to manage loss of material due to pitting, crevice, and microbiologically influenced corrosion with the Structures Monitoring program, citing generic Note G. The staff's evaluation of the acceptability of that program to manage loss of material is documented in SER Section 3.5.2.3.3. The staff's concern described in RAI 3.5.2-1 is resolved.

The staff's evaluation of the applicant's Structures Monitoring program is documented in SER Section 3.0.3.2.20. The staff noticed that the Structures Monitoring includes preventive actions to manage loss of preload for SS structural bolting through the proper selection of lubricants and installation torque or tension. The program also includes visual inspections for loose bolts and nuts at a frequency of at least every 5 years. Based on its review of components associated with item 3.3.1-15 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring program acceptable because proper selection of lubricants and installation torque, and followup monitoring for loose bolts and nuts, is capable of mitigating and detecting loss of preload prior to loss of intended function.

The staff concludes that for LRA item 3.3.1-15 the applicant 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, Crevice, Galvanic, and Microbiologically Influenced Corrosion, and Fouling That Leads to Corrosion

LRA Table 3.3.1, item 3.3.1-38 addresses steel heat exchanger components exposed to raw water, which will be managed for loss of material due to corrosion. For the AMR item that cites generic Note E, the LRA credits the ASME Section XI, Subsection IWF program to manage the aging effect for component supports in ASME Class 2 and 3 piping systems. The GALL Report recommends AMP XI.M20, "Open-Cycle Cooling Water System" to ensure that this aging effect is adequately managed. GALL Report AMP XI.M20 recommends using periodic visual inspections to manage the effects of aging. The staff noticed that the GALL Report does not have comparable items for carbon steel component supports exposed to raw water and that other component supports are managed by the ASME Section XI, Subsection IWF program through various AMR items in Table 3.5-1.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF program is documented in SER Section 3.0.3.2.18. The staff noticed that the ASME Section XI, Subsection IWF program proposes to manage the effects of aging for component supports through the use of periodic visual examinations. Based on its review of components associated with item 3.3.1-38 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWF program acceptable because the designated program is specifically intended to manage aging in component supports.

The staff concludes that for LRA item 3.3.1-38 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.4 Loss of Material Due to Pitting, Crevice Corrosion, and Fouling That Leads to Corrosion

LRA Table 3.3.1, item 3.3.1-40 addresses SS piping exposed to raw water, which will be managed for loss of material due to pitting, crevice corrosion and fouling that leads to corrosion. For the AMR item that cites generic Note E, the LRA credits the Structures Monitoring program to manage the aging effect for SS component supports for the EDG, HVAC, and other miscellaneous mechanical equipment. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M20 recommends using periodic visual inspections to manage the effects of aging. The staff noticed that the GALL Report does not have comparable items for SS component supports exposed to raw water and that other component supports are managed by the Structures Monitoring program through various AMR items in Table 3.5-1.

The staff's evaluation of the applicant's Structures Monitoring program is documented in SER Section 3.0.3.2.20. The staff noticed that the Structures Monitoring program proposes to manage the effects of aging for component supports through the use of periodic visual examinations. Based on its review of components associated with item 3.3.1-40 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring program acceptable because the designated program is specifically intended to manage component supports.

The staff concludes that for LRA item 3.3.1-40 the applicant 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 General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-54 addresses copper-alloy piping, piping components, and piping elements exposed to condensation. The GALL Report recommends GALL Report AMP XI.M24, "Compressed Air Monitoring," to manage loss of material due to general, pitting, and crevice corrosion for this component group. During its review of components associated with item number 3.3.1-54, for which the applicant cited generic Note B, the staff noticed that the LRA credits the Compressed Air Monitoring Program to manage this aging effect, consistent with the GALL Report guidance.

The staff also noticed that the components associated with item 3.3.1-54 include copper alloy greater than 15-percent zinc valve bodies. LRA Table 3.3.1, item 3.3.1-72 recommends that copper alloy greater than 15-percent zinc components exposed to raw water also be managed for loss of material due to selective leaching. The GALL Report, Table IX.D, explains that condensation on the surfaces of systems at temperatures below the dew point is considered "raw water" due to the potential for internal or external surface contamination. The applicant stated that loss of material due to selective leaching is not an applicable aging effect for the copper alloy greater than 15-percent zinc valve bodies because the component is not subject to prolonged wetting due to ponding or pooling of water. The staff evaluated the applicant's claim and finds it acceptable because the purpose of the Compressed Air Monitoring program is to prevent moisture and contaminants from occurring within the system. In addition, if moisture should accumulate due to a temporary excursion in air quality, the program's ongoing maintenance of appropriate dew point would limit the time at which the moisture would persist. As such, the accumulation of water in a compressed air system valve body over the time needed for selective leaching to occur is unlikely.

The staff concludes that for LRA item 3.3.1-54 the applicant 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 Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel

LRA Table 3.5.1, item 3.5.1-66 addresses concrete (accessible areas): interior and above-grade exterior exposed to air-indoor uncontrolled (external), air-outdoor (external), and air with borated water leakage (external), which will be managed for cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel. For the AMR items that cite generic Note E, the LRA credits the Fire Protection Program to manage the aging effect for concrete block fire barriers (masonry walls). However, the staff notes that the LRA also credits the Structures Monitoring Program to manage cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for these concrete block fire barriers (masonry walls). The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends periodic visual inspections of concrete structures at a frequency not to exceed 5 years to manage the effects of aging.

The staff's evaluation of the applicant's Fire Protection and Structure Monitoring Programs are documented in SER Sections 3.0.3.2.10 and 3.0.3.2.20, respectively. The staff noticed that the Fire Protection Program proposes to manage the effects of aging for concrete block fire barriers (masonry walls) through the use of visual inspections by personnel qualified and trained to perform the inspection activities, at a frequency consistent with its NRC-approved Fire Protection Program, which will be used to supplement the Structures Monitoring Program in managing cracking, loss of bond, and loss of material of concrete block fire barrier masonry walls. Based on its review of components associated with item 3.5.1-66 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Fire Protection Program acceptable because (1) the applicant's program is consistent, with enhancements, with GALL Report AMP XI.M26 which recommends periodic visual inspections of fire barrier walls, ceilings, and floors, and (2) the applicant's program will be enhanced to provide additional inspection guidance to identify age-related degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material.

The staff concludes that for LRA item 3.5.1-66 the applicant 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, Pitting, Crevice, and Microbiologically Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-90 addresses steel ducting and internal components exposed internally to condensation, which will be managed for loss of material. For the AMR item that cites generic Note E, the LRA credits the Fire Protection program to manage the aging effect for galvanized steel damper housings. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M38 recommends using visual inspections to manage the effects of aging.

The staff's evaluation of the applicant's Fire Protection program is documented in SER Section 3.0.3.2.10. The staff noticed that the Fire Protection program proposes to manage the effects of aging for galvanized steel damper housings through the use of visual inspections. Based on its review of components associated with item 3.3.1-90 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Fire Protection program acceptable because the program provides for visual inspections that are capable of detecting loss of material for all fire dampers at least once every 18 months.

3.3.2.1.8 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-100 addresses SS piping, piping components, and piping elements exposed to lubricating oil, which will be managed for loss of material. For the AMR item that cites generic Note E and plant-specific note 2, which states that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be substituted in the place of the Lubricating Oil Analysis Program to manage the aging effect(s) applicable to this component type, material, and environment combination. Furthermore, Note 2 states that the preventive measures and sampling activities performed by the Lubricating Oil Analysis Program are not applicable for the components exposed to lubricating oil in the positive displacement pump lubricating oil system because the positive displacement pump has been removed from service; and, therefore, the oil quality is not maintained.

The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effect for SS piping, piping components, and piping elements exposed to lubricating oil. The GALL Report recommends GALL Report AMP XI.M39 "Lubricating Oil Analysis," and XI.M32, "One-Time Inspection," programs to ensure that this aging effect is adequately managed. GALL Report AMP XI.M39 recommends maintaining oil system contaminants within acceptable limits through periodic sampling and analysis, and comparing the analytical results to predetermined limits that are associated with corrective actions such as filtering or oil replacement in order to manage the aging effects of loss of material due to corrosion or reduction of heat transfer due to fouling. Additionally, the One-Time Inspection Program will be used to verify that the effectiveness of the Lubricating Oil Analysis program is designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program proposes to manage the effects of aging for SS piping, piping components, and piping elements through the use of visual inspections. Based on its review of components associated with item 3.3.1-100 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the Internal Surfaces in Miscellaneous Piping and Ducting Components program is capable of detecting loss of material through the use of visual inspections. Additionally, because the component has been removed from service, testing oil quality for this component is not needed.

The staff concludes that for LRA item 3.3.1-100 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-99 addresses copper alloy, aluminum piping, piping components, and piping elements exposed to lubricating oil, which will be managed for loss of material. The AMR item cites generic Note E and plant-specific note 2, which state that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be substituted in the place of the Lubricating Oil Analysis Program to manage the aging effect(s) applicable to this component type, material, and environment combination. Furthermore, Note 2 states that the preventive measures and sampling activities performed by the Lubricating Oil Analysis Program are not applicable for the components exposed to lubricating oil in the positive displacement pump lubricating oil system since the positive displacement pump has been removed from service and, therefore, the oil quality is not maintained.

The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effect for carbon steel and gray cast iron. The GALL Report recommends GALL Report AMP XI.M39, "Lubricating Oil Analysis," and XI.M32, "One-Time Inspection" to ensure that this aging effect is adequately managed. GALL Report AMP XI.M39 recommends maintaining oil system contaminants within acceptable limits through periodic sampling and analysis, and comparing the analytical results to predetermined limits that are associated with corrective actions such as filtering or oil replacement in order to manage the aging effects of loss of material due to corrosion or reduction of heat transfer due to fouling. Additionally, the One-Time Inspection Program will be used to verify that the effectiveness of the Lubricating Oil Analysis program is designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program proposes to manage the effects of aging for carbon steel and gray cast iron components through the use of visual inspections. Based on its review of components associated with item 3.3.1-99 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the Internal Surfaces in Miscellaneous Piping and Ducting Components program is capable in detecting loss of material through the use of visual inspections. Additionally, because the component has been removed from service, testing oil quality for this component is not needed.

The staff concludes that for LRA item 3.3.1-99 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-97 addresses carbon steel and gray cast iron piping, piping components, and piping elements exposed to lubricating oil (internal), which will be managed for loss of material. AMR item that cites generic Note E and plant-specific note 2, which states that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be substituted in the place of the Lubricating Oil Analysis Program to manage the aging effect(s) applicable to this component type, material, and environment combination. Furthermore, Note 2 states that the preventive measures and sampling activities performed by the Lubricating Oil Analysis Program are not applicable for the components exposed to lubricating oil in the positive displacement pump lubricating oil system because the positive displacement pump has been removed from service and, therefore, the oil quality is not maintained.

The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effect for carbon steel and gray cast iron. The GALL Report recommends GALL Report AMP XI.M39, “Lubricating Oil Analysis,” and XI.M32, “One-Time Inspection” to ensure that this aging effect is adequately managed. GALL Report AMP XI.M39 recommends maintaining oil system contaminants within acceptable limits through periodic sampling and analysis, and comparing the analytical results to predetermined limits that are associated with corrective actions such as filtering or oil replacement in order to manage the aging effects of loss of material due to corrosion or reduction of heat transfer due to fouling. Additionally, the One-Time Inspection Program will be used to verify that the effectiveness of the Lubricating Oil analysis program is designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program proposes to manage the effects of aging for carbon steel and gray cast iron components through the use of visual inspections. Based on its review of components associated with item 3.3.1-97 for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage the effects of aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the Internal Surfaces in Miscellaneous Piping and Ducting Components program is capable in detecting loss of material through the use of visual inspections. Additionally, because the component has been removed from service, testing oil quality for this component is not needed.

The staff concludes that for LRA item 3.3.1-97 the applicant 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 No Aging Effect Requiring Management

LRA Table 3.3.1, item 3.3.1-123 (Braidwood only), addresses titanium piping and piping components exposed to raw water for which there is no identified AERM and no AMP. The staff noticed that SRP-LR Table 3.3-1, item 3.3.1-123, states that for titanium components manufactured from ASTM Grades 1, 2, 7, 11, or 12 that contain greater than 5 percent aluminum or 0.20 percent oxygen or any amount of tin, there is no recommended AERM and no recommended AMP. The staff also noticed that item 3.3.1-123 and its corresponding GALL Report items, AP-152 and AP-161, contain an editorial error. NUREG-1950, “Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG-1801 and NUREG-1800,” states that ASTM Grades 1, 2, 7, 11, or 12 titanium are not susceptible to either loss of material or SCC in the raw water environment (regardless of the levels of aluminum, oxygen, and tin).

During the AMP audit, the staff noticed that titanium alloy piping components (used in the service water system) that cite item 3.3.1-123 are constructed of a titanium material grade that is listed as not susceptible to loss of material and cracking. During the audit, the staff also noticed that the plant-specific drawing states that the titanium material may be substituted with

SS. The staff noticed that, for SS service water system components exposed to raw water in the auxiliary systems, the applicant manages loss of material with the Open-Cycle Cooling Water System Program, citing LRA items 3.3.1-40 and 3.3.1-41. The staff's evaluations of those items are documented elsewhere in SER Section 3.3.2.1.

The staff finds the applicant's proposal that there are no AERM for titanium piping components citing LRA Table 3.3.1 item 3.3.1-123 acceptable because it is consistent with NUREG-1500, item AP-161.

On the basis of its review, the staff concludes that for titanium components citing LRA Table 3.3.1 item 3.3.1-123, with no AERM, the applicant has appropriately evaluated the material and environment combinations and 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).

3.3.2.1.10 Cracking Due to Stress Corrosion Cracking

The staff's evaluation for Table 3.3.1, item 3.3.1-132, which addresses cracking of insulated SS piping, piping components, and piping elements externally exposed to condensation and outdoor air, is documented in SER Section 3.2.2.1.3.

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

LRA Table 3.5.1, item 3.5.1-80 addresses steel structural bolting exposed to air-indoor uncontrolled (external) and air with borated water leakage (external), which will be managed for loss of material due to general, pitting and crevice corrosion. For the AMR items that cites generic Note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect for carbon and low alloy steel structural bolting in the cranes and hoist, and fuel handling and fuel storage systems. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends periodic visual inspections to manage the effects of aging.

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 3.0.3.2.8. The staff noticed that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the effects of aging for carbon and LAS structural bolting through the use of periodic visual inspections. The LRA states that the program procedures are based on the ASME Code B30 standards which rely on periodic visual inspections to manage loss of material. LRA Table A.5, "License Renewal Commitment List," Commitment No. 13, states that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be enhanced before the period of extended operation to "include inspections of structural components and bolting for loss of material due to corrosion." Based on its review of components associated with item 3.5.1-80 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because the periodic visual inspections, performed at a frequency consistent with ASME B30 (either annually or just prior to use for those handling systems infrequently in service), will be able to detect a loss of material due to general, pitting, and crevice corrosion.

LRA Table 3.5.1, item 3.5.1-82 addresses steel structural bolting exposed to air-outdoor (external), which will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect for carbon and LAS structural bolting in the cranes and hoist, and fuel handling and fuel storage systems. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends periodic visual inspections to manage the effects of aging.

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 3.0.3.2.8. The staff noticed that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the effects of aging for carbon and LAS structural bolting through the use of periodic visual inspections. The LRA states that the program procedures are based on the ASME Code B30 standards which rely on periodic visual inspections to manage loss of material. LRA Table A.5, "License Renewal Commitment List," Commitment No. 13, states that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be enhanced before the period of extended operation to "include inspections of structural components and bolting for loss of material due to corrosion." Based on its review of components associated with item 3.5.1-82 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because periodic visual inspections, performed at a frequency consistent with ASME B30 (either annually or just prior to use for those handling systems infrequently in service), will be able to detect a loss of material due to general, pitting, and crevice corrosion.

The staff concludes that for LRA items 3.5.1-80 and 82, the applicant 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 Preload Due to Self-Loosening

LRA Table 3.5.1, item 3.5.1-88 addresses steel and SS structural bolting exposed to air with borated water leakage (external), treated borated water (external), air-indoor uncontrolled (external), or air-outdoor (external), which will be managed for loss of preload due to self-loosening. For the AMR items that cite generic Note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect for carbon and LAS as well as SS structural bolting in the cranes and hoist, and fuel handling and fuel storage systems. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends periodic visual inspections of structural bolting to manage the effects of aging.

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 3.0.3.2.8. The staff noticed that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the effects of aging for carbon and LAS as well as SS structural bolting through the use of visual inspections. The LRA states that structural bolting is monitored for loss of preload by inspecting for loose or missing bolts, or nuts, and that the frequency of inspections are consistent with the ASME Code B30 standards. LRA Table A.5, “License Renewal Commitment List,” Commitment No. 13 also states that the program will be enhanced before the period of extended operation to include inspections of structural bolting for evidence of loss of preload. Based on its review of components associated with item 3.5.1-88 for which the applicant cited generic Note E, the staff finds the applicant’s proposal to manage the effects of aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because (1) visual inspections of structural bolts are performed at a frequency consistent with the ASME Code B30 (either annually or just prior to use for those systems infrequently in service), (2) the parameters monitored or inspected include loose or missing bolts or nuts, and (3) the program will be enhanced to include inspections for loss of preload of structural bolting, consistent with the recommendations in the GALL Report.

The staff concludes that for LRA item 3.5.1-88 the applicant 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).

3.3.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.3.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the auxiliary systems components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- cracking due to SCC and cyclic loading
- cracking due to SCC
- loss of material due to cladding breach
- loss of material due to pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant 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 it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant’s further evaluations against the criteria contained in SRP-LR Section 3.3.2.2. The staff’s review of the applicant’s further evaluation follows.

3.3.2.2.1 Cumulative Fatigue Damage

LRA Section 3.3.2.2.1, which is associated with LRA Table 3.3.1, items 3.3.1-1 and 3.3.1-2, addresses how steel cranes: structural girders exposed to air-indoor, uncontrolled (external) and steel and SS piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water in auxiliary systems are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Sections 4.3 and 4.7.

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR Section 3.3.2.2.1, which states that fatigue of these auxiliary system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1). The staff reviewed the applicant's AMR line items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel cranes structural girders exposed to air-indoor uncontrolled (external), and in steel and SS piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water.

The staff concludes that the applicant has met the SRP-LR Section 3.3.2.2.1 criteria. For those line items that apply to LRA Section 3.3.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Sections 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAA for these components.

In LRA Table 3.3.2-9, the applicant stated there is a TLAA for carbon steel crane/hoist (bridge/trolley/girders) exposed to air-outdoor (external), which cites generic Note G. The staff confirmed that there is a TLAA, as documented in LRA Section 4.7.2, for this component and material. The staff's evaluation of the TLAA for crane load cycle limits is documented in SER Section 4.7.2.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

LRA Section 3.3.2.2.2, associated with LRA Table 3.3.1, item 3.3.1-3, addresses SS nonregenerative heat exchanger components exposed to treated borated water greater than 140 °F (60 °C), which will be managed for cracking due to SCC and cyclic loading by the Water Chemistry, One-Time Inspection, and Closed Treated Water Systems Programs. The criteria in the SRP-LR Section 3.3.2.2.2 state that cracking due to SCC and cyclic loading could occur for SS nonregenerative heat exchangers and that a plant-specific program be evaluated to verify the absence of cracking. The SRP-LR also states that an acceptable verification program includes temperature and radioactivity monitoring of the shell-side water and eddy current testing of the tubes. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the effectiveness of the Water Chemistry Program will be verified with the One-Time Inspection Program by utilizing eddy current testing of the heat exchanger tubes to verify the absence of cracking. The applicant also stated that the Closed Treated Water Systems Program includes activities to monitor the temperature and radioactivity of the shell-side water and any deficiencies will be documented in accordance with the CAP.

The staff's evaluations of the applicant's Water Chemistry Program, One-Time Inspection Program, and Closed Treated Water Systems Program are documented in SER Sections 3.0.3.1.1, 3.0.3.1.6 and 3.0.3.2.7, respectively. The staff did not identify any past plant-specific OE with tube cracking in the CVCS's nonregenerative heat exchangers, which allows them to be managed through a one-time inspection. The staff notes that cracking can be identified by both eddy current testing of the heat exchanger tubes through the One-Time Inspection Program and by monitoring the shell-side water for temperature and radioactivity through the Closed Treated Water Systems Program. Based on the above, in its review of components associated with item 3.3.1-3, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the above programs is acceptable.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking

As revised by letter dated January 13, 2014, LRA Section 3.3.2.2.3, associated with LRA Table 3.3.1, item 3.3.1-4 addresses SS piping, piping components, piping elements, and tanks exposed to outdoor air, which will be managed for cracking due to SCC by the External Surfaces Monitoring of Mechanical Components and One-Time Inspection Programs. The criteria in SRP-LR Section 3.3.2.2.3 states that cracking due to SCC could occur for SS piping, piping components, piping elements, and tanks exposed to outdoor air, in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. The GALL Report recommends further evaluation to determine whether an AMP is needed to manage this aging effect based on the environmental conditions applicable to the plant and requirements applicable to the components. The SRP-LR also states that GALL AMP XI.M36, "External Surface Monitoring of Mechanical Components," is an acceptable method to manage cracking due to SCC. The applicant addressed the further evaluation criteria of the SRP-LR by stating that cracking of liquid-filled uninsulated SS piping exposed to outdoor air will be managed with the External Surfaces Monitoring of Mechanical Components Program. Cracking of gas-filled (e.g., diesel exhaust) uninsulated piping will be managed with the One-Time Inspection Program.

The staff's evaluation of the applicant's One-Time Inspection and External Surfaces Monitoring of Mechanical Components Programs is documented in SER Sections 3.0.3.1.6 and 3.0.3.1.9. The staff noticed that the One-Time Inspection Program includes visual inspections of a representative sample of gas-filled (diesel exhaust) piping and piping components for discoloration or staining that would indicate leakage of exhaust gases through cracks. If evidence of cracking is observed, the One-Time Inspection Program includes an evaluation of the need for followup examinations. The staff also noticed that the External Surfaces Monitoring of Mechanical Components Program includes periodic visual inspections, at least once per refueling cycle, of liquid-filled piping and piping components for leakage that would be indicative of cracking. In its review of components associated with item 3.3.1-4, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the One-Time Inspection and External Surfaces Monitoring of Mechanical Components Programs is acceptable because the visual inspections described above are capable of detecting component leakage associated with cracking prior to loss of intended functions.

Based on the programs identified, the staff determines that the applicant's programs meet SRP-LR Section 3.3.2.2.3 criteria. For those items associated with LRA Section 3.3.2.2.3, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will 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 Loss of Material Due to Cladding Breach

LRA Section 3.3.2.2.4, associated with LRA Table 3.3.1, item 3.3.1-5, addresses loss of material due to cladding breach in steel with SS or nickel-alloy cladding charging pump casings exposed to treated borated water. The staff noticed that this item is associated with NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks." The applicant stated that this item is not applicable because there are no steel with SS or nickel-alloy cladding charging pump casings exposed to treated borated water in the auxiliary systems. The staff evaluated the applicant's claim and finds it acceptable because a review of LRA Section 3.3 and UFSAR Table 9.3-3 confirmed that the charging pumps are constructed of SS rather than steel with SS or nickel-alloy cladding; consequently, loss of material due to boric acid corrosion is not an applicable aging effect.

3.3.2.2.5 Loss of Material Due to Pitting and Crevice Corrosion

Item 1. LRA Section 3.3.2.2.5, associated with LRA Table 3.3.1, item 3.3.1-6, addresses SS piping, piping components, piping elements, and tanks exposed to outdoor air, which will be managed for loss of material due to pitting and crevice corrosion by the External Surfaces Monitoring of Mechanical Components Program. The criteria in SRP-LR Section 3.3.2.2.5, item 1, state that loss of material due to pitting and crevice corrosion could occur for SS piping, piping components, piping elements, and tanks exposed to outdoor air. The SRP-LR also states that possibility of pitting and crevice corrosion also extends to components exposed to air that has been recently introduced into the building (i.e., components near intake vents). The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material in SS piping, piping components, and piping elements will be managed by the External Surfaces Monitoring of Mechanical Components Program.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.9. In its review of components associated with item 3.3.1-6, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage the effects of aging using the External Surfaces Monitoring of Mechanical Components Program is acceptable because the AMP provides for management of loss of material through visual inspections of external surfaces at least once per refueling cycle, which are capable of detecting corrosion prior to loss of intended function, consistent with GALL Report guidance.

Based on the program identified, the staff determines that the applicant's program meets SRP-LR Section 3.3.2.2.5 criteria. For those items associated with LRA Section 3.3.2.2.5, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will 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 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.3.2.2.7 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of OE of AMPs.

3.3.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1 through 3.3.2-23, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-23, the applicant indicated, via Notes F through J, which the combination of component type, material, environment, and AERM does not correspond to an AMR item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR 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 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. The staff's evaluation is discussed in the following sections.

3.3.2.3.1 Auxiliary Building Ventilation System—Summary of Aging Management Evaluation—LRA Table 3.3.2-1

<u>Aluminum Alloy Heat Exchanger Fins Exposed Externally to Condensation</u>. In LRA Tables 3.3.2-1, 3.3.2-8, and 3.3.2-11, the applicant stated that aluminum alloy heat exchanger fins exposed externally to condensation will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The GALL Report states that aluminum piping, piping components, and piping elements exposed internally to condensation are susceptible to loss of material due to pitting and crevice corrosion and recommends GALL Report XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage the aging effect. However, the applicant identified reduction of heat transfer as an additional aging effect, because these components have a heat transfer intended function. However, the applicant did not address loss of material as an aging effect for the aluminum alloy heat exchanger fins. Although the LRA does not address loss of material for the fins, the staff noticed that the aging management approach discussed below, in which the applicant proposed to manage reduction of heat transfer using visual inspections, also would be expected to identify corrosion of the fins before their heat transfer function would be challenged.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections to detect fouling of heat exchanger surfaces. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage the effects of aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections capable of detecting reduction of heat transfer.

Copper-Alloy Heat Exchanger Tubes Exposed Externally to Condensation. In LRA Tables 3.3.2-1, 3.3.2-7, 3.3.2-8, and 3.3.2-11, the applicant stated that copper-alloy heat exchanger tubes exposed externally to condensation will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The GALL Report states that copper-alloy piping, piping components, and piping elements exposed to condensation are susceptible to loss of material due to general, pitting, and crevice corrosion and recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to manage the aging effect for external surfaces and AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage the aging effect for internal surfaces. The staff noticed that the applicant addressed loss of material for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-1, 3.3.2-7, 3.3.2-8, and 3.3.2-11. However, the staff noticed that the applicant identified reduction of heat transfer as an additional aging effect, because these components have a heat transfer intended function.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections to detect fouling of heat exchanger surfaces. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage the effects of aging using the Inspections of Internal Surfaces in Miscellaneous Piping and Ducting Components acceptable because the program will manage reduction of heat transfer using visual inspections, which would be able to identify corrosion of the fins before their heat transfer function would be challenged.

Elastomeric Door Seals, Filter Housing, and Piping Components Exposed Internally to Condensation. In LRA Tables 3.3.2-1, 3.3.2-7, and 3.3.2-8, the applicant stated that elastomeric door seals, filter housings, piping, piping components, piping elements, and damper housings exposed internally to condensation will be managed for loss of material, hardening, and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. For the cited environment, the staff noticed that components operating below dew point exposed to uncontrolled indoor air can result in condensation. The staff also noticed that aging effects being managed for other elastomeric items exposed to uncontrolled air in the GALL Report (e.g., items VII.F1.AP-102, AP-103, AP-113) also included loss of material, hardening, and loss of strength. Consequently, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections to detect loss of material and physical manipulation to assess changes in polymer properties. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage the effects of aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections and physical manipulation of elastomeric components that are capable of detecting loss of material, hardening, and loss of strength.

The staff concludes for items in LRA Table 3.3.2-1 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.2 Chemical & Volume Control System—Summary of Aging Management Evaluation—LRA Table 3.3.2-2

Insulated Stainless Steel Piping, Piping Components, and Piping Elements Exposed to Condensation. The staff's evaluation for insulated SS piping, piping components, and piping elements externally exposed to condensation, for which the applicant stated that cracking is not applicable and proposed no AMP, citing generic Note I, is documented in SER Section 3.2.2.1.3.

The staff concludes for items in LRA Table 3.3.2-2 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.3 Chilled Water System—Summary of Aging Management Evaluation—LRA Table 3.3.2-3

Insulated Stainless Steel Piping, Piping Components, Piping Elements, and Valve Bodies Exposed to Condensation. The staff's evaluation for insulated SS piping, piping components, piping elements, and valve bodies externally exposed to condensation, for which the applicant stated that cracking is not applicable and proposed no AMP, citing generic Note I, is documented in SER Section 3.2.2.1.3.

The staff concludes for items in LRA Table 3.3.2-3 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.4 Circulating Water System—Summary of Aging Management Evaluation—LRA Table 3.3.2-4

Stainless Steel Piping, Piping Components, and Piping Elements Exposed to Treated Water. The staff's evaluation for SS piping, piping components, and piping elements exposed to treated water, which will be managed for wall thinning due to mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program and are associated with generic Note H, is documented in 3.1.2.3.4.

Polymeric Valve Bodies Exposed to Raw Water (internal) (Byron only). In LRA Table 3.3.2-4, the applicant stated that for polymeric valve bodies exposed to raw water (internal) at Byron only, there is no aging effect and no AMP is proposed. The AMR item cites generic Note G. The AMR item cites plant-specific note 2, which states:

> The Raw Water environment is not in NUREG-1801 for this component and material. There is no aging effect for this component, material, and environment combination. Based on plant operating experience, there are no aging effects requiring management for the polymer piping in a raw water environment. This material does not experience aging effects unless exposed to elevated temperatures or radiation levels capable of attacking the specific chemical composition. The material in this water environment is not expected to experience significant aging effects due to elevated temperatures or radiation levels. The pipe material is chlorinated polyvinyl chloride (CPVC) manufactured in accordance with ASTM F1970-12, which is installed on the copper ion generator skid at Byron only. There are no chemicals injected into the Circulating Water System at the River Screen House.

The staff reviewed the associated item in the LRA to confirm that no credible aging effects are applicable for this component, material and environment combination. The staff noticed that the "Effects of UV Light and Weather on Plastics and Elastomers," Liesl K. Massey, William Andrew Publishing, 2007, Chapter 52, "Chlorinated Polyvinyl Chloride," states, "[c]hlorinated polyvinyl chloride(CPVC) has physical properties similar to PVC, but offers higher heat deflection properties for extended temperature range uses." The staff also noticed that "PVC Pipe – Design and Installation – Manual of Water Supply Practices," M23, American Water Works Association, Second Edition, 2002, states:

> PVC and PVCO [oriented PVC] pipes are resistant to almost all types of corrosion-both chemical and electrochemical-that are experienced in underground piping systems. Because PVC is a nonconductor, galvanic and electrochemical effects are nonexistent in PVC piping systems. PVC pipe cannot be damaged by aggressive waters or corrosive soils.

It also states, "PVC pipe is nearly totally resistant to biological attack. Biological attack can be described as degradation or deterioration caused by the action of living microorganisms or macroorganisms." It further states that, "PVC pipe is well suited to applications where abrasive conditions are anticipated."

Appendix A, Chemical Resistance Tables of this document, lists PVC as generally resistant to chemicals up to 140 °F, such as bleach (12.5 percent active chlorine), potassium hydroxide, sodium hydroxide, kerosene, hydrochloric acid, hydrogen peroxide (90 percent), sea water, soaps, and sulfuric acid (70 percent). The staff noticed that "PVC Formulary," G. Wypych, ChemTec Publishing, 2009 states, "[a]s a general rule, PVC is not resistant to polar solvents but very resistant to acids, bases, salts, alcohols, esters, and hydrocarbons."

The staff finds the applicant's proposal acceptable based on its review of the above documents, because PVC, and likewise CPVC, is resistant to the raw water that would be present in the circulating water piping.

The staff concludes for items in LRA Table 3.3.2-4 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL

Report, and 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).

3.3.2.3.5 Component Cooling System—Summary of Aging Management Evaluation—LRA Table 3.3.2-5

Carbon or LAS Heat Exchanger Tube Sheets Exposed to Closed-Cycle Cooling Water. In LRA Table 3.3.2-5, the applicant stated that carbon or LAS with nickel alloy cladding heat exchanger tube sheets exposed to closed-cycle cooling water will be managed for loss of material by the Closed Treated Water Systems Program. The AMR item cites generic Note G. As discussed in the staff's audit report for the Closed Treated Water Systems Program, the staff confirmed that there is no cladding on the closed-cycle cooling water side of the subject component cooling heat exchanger tube sheets, contrary to the material description in this AMR item. The nickel alloy cladding is limited to the service water side of the heat exchangers.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that neither the chemistry nor the temperature of the component cooling water is conducive to SCC of the carbon steel tube sheet. Principles and Prevention of Corrosion, 2nd Edition (D. Jones, Prentice Hall, 2005) states that cracking of carbon steels is a concern when exposed to hot caustic (e.g., sodium hydroxide) and nitrate solutions, as well as other environments typically associated with the chemical processing industry, such as sulfuric acid, liquid ammonia, and cyanides. The staff noticed that the water in the applicant's component cooling systems is maintained in accordance with EPRI Report 1007820, Revision 1, "Closed Cooling Water Guidelines," for nitrite-based programs. These guidelines contain control and diagnostic parameters to ensure that water chemistry is not conducive to SCC, such as the monitoring of nitrates and ammonia. In addition, UFSAR Table 9.2-3 states that the maximum design temperature of the component cooling water in the heat exchangers is 120 °F (49 °C). This temperature is less than the 160 to 180 °F (71 to 82 °C) SCC threshold described in Corrosion Engineering, 3rd Edition (M. Fontana, McGraw-Hill, 1986) for carbon steel in sodium hydroxide solutions of less than 20 percent concentration. Therefore, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Closed Treated Water Systems Program is documented in SER Section 3.0.3.2.7. The staff noticed that the program's water chemistry controls for the component cooling system include nitrite-based corrosion inhibitors that passivate steel surfaces. In addition, the program includes opportunistic and periodic (at least once every 10 years) visual and nondestructive examinations of a sample of components to detect loss of material. The staff finds the applicant's proposal to manage the effects of aging using the Closed Treated Water Systems Program acceptable because the program's water chemistry controls are capable of mitigating the environmental effects on loss of material and because the opportunistic and periodic visual and nondestructive inspections can detect loss of material prior to loss of intended function.

The staff concludes for items in LRA Table 3.3.2-5 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.6 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 review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the compressed air system component groups are consistent with the GALL Report.

3.3.2.3.7 Containment Ventilation System—Summary of Aging Management Evaluation—LRA Table 3.3.2-7

Copper-Alloy Heat Exchanger Tubes Exposed Externally to Condensation. The staff's evaluation for copper-alloy heat exchanger tubes exposed externally to condensation, which will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

Elastomeric Door Seals, Damper Housing, and Piping Components Exposed Internally to Condensation. The staff's evaluation for elastomeric door seals, damper housing, piping, piping components, and piping elements exposed internally to condensation, which will be managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

Stainless Steel, Carbon and Low Alloy Steel Bolting Exposed Externally to Condensation. In LRA Table 3.3.2-7, the applicant stated that SS, carbon, and LAS bolting exposed externally to condensation will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that SS, carbon and LAS bolting exposed to uncontrolled indoor air (uncontrolled indoor air is an environment associated with systems with temperatures higher than the dew point, (i.e., condensation can occur, but only rarely)) is susceptible to loss of material and preload. The GALL Report recommends AMP XI.M18, "Bolting Integrity" to manage the aging effects for pressure-retaining bolting and XI.S6, "Structures Monitoring," to manage the aging effects for structural bolting. The applicant addressed the GALL Report identified aging effect of loss of preload for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-7.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections to detection corrosion. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage loss of material using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections capable of detecting loss of material.

The staff concludes for items in LRA Table 3.3.2-7 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL

Report, and 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).

3.3.2.3.8 Control Area Ventilation System—Summary of Aging Management Evaluation—LRA Table 3.3.2-8

Aluminum Alloy Heat Exchanger Fins Exposed Externally to Condensation. The staff's evaluation for aluminum alloy heat exchanger fins exposed externally to condensation, which will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

Copper-Alloy Heat Exchanger Tubes Exposed Externally to Condensation. The staff's evaluation for copper-alloy heat exchanger tubes exposed externally to condensation, which will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

Elastomeric Door Seals, Damper Housing, and Piping Components Exposed Internally to Condensation. The staff's evaluation for elastomeric door seals, damper housing, piping, piping components, and piping elements exposed internally to condensation, which will be managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

The staff concludes for items in LRA Table 3.3.2-8 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.9 Cranes and Hoists—Summary of Aging Management Evaluation—LRA Table 3.3.2-9

Carbon Steel Cranes and Hoists Exposed to Air-Outdoor (external). In LRA Table 3.3.2-9, the applicant stated that carbon steel crane and hoist components (bridges, trolleys, girders, and rail systems) exposed to air-outdoor (external) will be managed for loss of material by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program. The AMR items cite generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report items VII.I.A-78 and VII.H.S-41, which state that steel external surfaces exposed to air-outdoor (external) are susceptible to loss of material due to general corrosion, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program is documented in SER Section 3.0.3.2.8. The staff noticed that the applicant's program is based on the ASME B30 series standards, which include inspections for loss of material that are applicable to outdoor cranes and hoists. ASME Standard B30.2-2011, "Overhead and Gantry Cranes," recommends that inspections for corrosion and wear be conducted yearly for normal and heavy service cranes and just prior to service for infrequently used cranes. The staff finds the applicant's proposal to manage the effects of aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling System program acceptable because the AMP provides for management of loss of material through periodic visual inspections for corrosion and wear that are capable of detecting degradation prior to loss of intended function.

The staff concludes for items in LRA Table 3.3.2-9 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.10 Demineralized Water Systems—Summary of Aging Management Evaluation—LRA Table 3.3.2-10

<u>Carbon Steel, Low Alloy Steel, and Stainless Steel Bolting Exposed to Raw Water</u>. In LRA Tables 3.3.2-10, 3.3.2-12, and 3.3.2-22, the applicant stated that carbon steel (Byron only), LAS (Byron only), and SS bolting exposed to raw water will be managed for loss of material by the Bolting Integrity Program. The AMR items cite generic Note H and plant-specific Note 1, which states that inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that steel and SS bolting exposed to raw water is susceptible to loss of preload due to thermal effects, gasket creep, and self-loosening and recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage the aging effect. However the applicant has identified loss of material as an additional aging effect. The applicant addressed the GALL Report identified aging effect for this component, material and environment combination in other AMR items in LRA Tables 3.3.2-10, 3.3.2-12, and 3.3.2-22.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The staff noticed that GALL Report AMP XI.M18 does not specifically address the inspection of submerged bolting. As a result, the staff evaluated whether the component maintenance activities cited in plant-specific note 1 will be performed with sufficient frequency such that bolting degradation can be identified prior to loss of intended function. As discussed in the audit report of the applicant's program and SER Section 3.0.3.2.4, the staff noticed that component maintenance provides for a representative sample of steel and SS bolting to be visually inspected at a frequency that is generally consistent with GALL Report guidance in other AMPs for normally inaccessible components (at least every 10 years). As a result, the staff finds the applicant's proposal to manage loss of material using the Bolting Integrity Program acceptable because the program includes visual inspections that are conducted at a frequency that is capable of detecting aging prior to loss of intended function.

The staff concludes for items in LRA Table 3.3.2-10 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.11 Emergency Diesel Generator & Auxiliaries System—Summary of Aging Management Evaluation—LRA Table 3.3.2-11

Aluminum Alloy Heat Exchanger Fins Exposed Externally to Condensation. The staff's evaluation for aluminum alloy heat exchanger fins exposed externally to condensation, which will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

Carbon Steel Piping Exposed to Diesel Exhaust. In LRA Table 3.3.2-11, the applicant stated that carbon steel piping exposed to diesel exhaust (internal) will be managed for cumulative fatigue damage by a TLAA. The AMR item cites generic Note H, which states that the TLAA is evaluated in LRA Section 4.3. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3, for this component and material. The staff's evaluation of the fatigue TLAA for the EDG and auxiliaries system is documented in SER Section 4.3.

Copper-Alloy Heat Exchanger Tubes Exposed Externally to Condensation. The staff's evaluation for copper-alloy heat exchanger tubes exposed externally to condensation, which will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and are associated with generic Note G, is documented in SER Section 3.3.2.3.1.

Copper-Alloy with Less than 15 Percent Zinc Heat Exchanger (EDG Fuel Oil Cooler) Tubes Exposed to Fuel Oil (external). In LRA Table 3.3.2-11, the applicant stated that copper-alloy with less than 15 percent zinc heat exchanger (EDG Fuel Oil Cooler) tubes exposed to fuel oil (external) will be managed for reduction of heat transfer by the Fuel Oil Chemistry program. The AMR item cites generic Note G, and plant-specific note 3, which states that the Fuel Oil Chemistry and the One-Time Inspection Programs will be used to manage the aging effects for this component, material, and environment combination.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that the applicant addressed loss of material (due to general, pitting, crevice, and microbiologically-influenced corrosion) for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-11. Based on its review of the GALL Report, which states that copper alloy is vulnerable to general, pitting, crevice, and microbiologically-influenced corrosion, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Fuel Oil Chemistry and One-Time Inspection are documented in SER Section 3.0.3.2.13 and 3.0.3.1.6, respectively. The staff finds the applicant's proposal to manage the effects of aging using the Fuel Oil Chemistry and the One-Time Inspection Programs acceptable because fuel oil quality is maintained by monitoring and controlling contaminants in fuel oil, which could deposit on tubes and lead to fouling. In addition, the One-Time Inspection Program uses visual inspection techniques capable of identifying loss of material to verify the effectiveness of the Fuel Oil Chemistry program.

Copper Alloy with 15 Percent or More Zinc Piping, Piping Components, Piping Elements, Heat Exchanger Components, and Valve Bodies Exposed to Closed-Cycle Cooling Water. In LRA Tables 3.3.2-11 and 3.3.2-21, the applicant stated that copper-alloy with 15 percent or more zinc piping, piping components, piping elements, heat exchanger components, and valve bodies exposed to closed cycle cooling water will be managed for cracking by the Closed Treated Water Systems Program. The AMR items cite generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that copper-alloy components exposed to closed-cycle cooling water are susceptible to loss of material due to general, pitting, crevice, and galvanic corrosion and reduction of heat transfer due to fouling (heat exchanger tubes only) and recommends GALL Report AMP XI.M21A, "Closed Treated Water Systems," to manage these aging effects. The staff also noticed that the GALL Report states that copper-alloy components with greater than 15 percent zinc are susceptible to loss of material due to selective leaching and recommends GALL Report AMP XI.M33, "Selective Leaching," to manage the aging effect. However the applicant has identified cracking as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-11 and 3.3.2-21.

The staff's evaluation of the applicant's Closed Treated Water Systems Program is documented in SER Section 3.0.3.2.7. The staff noticed that the program includes opportunistic and periodic (at least once every 10 years) visual and nondestructive examinations of a sample of components to detect cracking, consistent with GALL Report AMP XI.M21A. As noted in the Audit Report of the Closed Treated Water Systems Program, the existing program includes eddy current surveillances of the copper with greater than 15 percent zinc EDG jacket water coolers, which are included in the subject components. The staff finds the applicant's proposal to manage cracking using the Closed Treated Water Systems Program acceptable because the program's water chemistry controls are capable of mitigating the environmental effects on cracking and because the opportunistic and periodic inspections can detect cracking prior to loss of intended function.

<u>Zinc Filter Housings Exposed Internally to Condensation</u>. In LRA Table 3.3.2-11, the applicant stated that zinc filter housings exposed internally to condensation will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR item cites generic Note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states that galvanized steel (i.e., steel coated with a protective zinc coating) exposed to outdoor air (i.e., condensation) should be managed for loss of material, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections to detect corrosion. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage the effects of aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections capable of detecting loss of material.

<u>Zinc Filter Housings Exposed to Uncontrolled Indoor Air</u>. In LRA Table 3.3.2-11, the applicant stated that zinc filter housings externally exposed to uncontrolled indoor air have no aging effect and that no AMP is needed. The AMR item cites generic note F and plant-specific note 2, which

states that the component is fabricated from zinc and has no aging effects in an indoor air environment.

The staff reviewed the associated item in the LRA and considered whether there are any credible aging effects for this component, material, and environment description. According to the ASM Handbook, Volume 13B, the corrosion rate of zinc in an indoor atmosphere is "very low, typically below 0.1 μm/yr (0.004 mil/yr)…" and "pitting is not a common form of corrosion in zinc applications." In addition, the ASM Handbook states that "stress-corrosion cracking is generally not encountered by zinc products that are normally used for nonstructural applications." Because zinc is effectively resistant to corrosion in indoor atmospheres, the staff finds that the applicant's determination that zinc filter housings exposed to uncontrolled indoor air have no aging effects is reasonable. Also, during the staff's audit of the applicant's AMPs, the staff noticed that the applicant changes the diesel air start system filters once every 6 years. Therefore, the applicant will have periodic opportunities to notice any appreciable material degradation in the filter housings during this maintenance activity.

The staff concludes for items in LRA Table 3.3.2-11 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.12 Fire Protection System—Summary of Aging Management Evaluation—LRA Table 3.3.2-12

<u>Earthen Water Control Structure Exposed to Outdoor Air</u>. In LRA Table 3.3.2-12, the applicant stated that the earthen water control structure (i.e., fuel oil storage tank berm) exposed to outdoor air will be managed for loss or material or loss of form by the Fire Protection and Structures Monitoring programs. The AMR item cites generic note G and plant-specific note 3, which states that the Fire Protection and Structures Monitoring programs will be used to manage the aging effect.

The staff reviewed the associated item in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. According to the GALL Report and SRP-LR, earthen water control structures (e.g., dams, embankments) are subject to a loss of material or loss of form. The staff considers the fuel oil storage tank earthen berm to be similar to an earthen embankment; therefore, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Fire Protection and Structures Monitoring programs are documented in SER Sections 3.0.3.2.10 and 3.0.3.2.20, respectively. The Fire Protection program will be enhanced to include visual inspections of the fuel oil storage tank berm. The Structures Monitoring program also will be enhanced to include the berm as an applicable structure to be inspected at least once every 5 years. The staff finds the applicant's proposal to manage the effects of aging using the Fire Protection and Structures Monitoring programs acceptable because inclusion of the earthen berm within these programs will ensure that the structure is periodically inspected for loss of material by methods capable of detecting a gross loss of material or form.

<u>Ceramic and Mineral Fiber Fire Barriers Exposed to Uncontrolled Indoor Air or Air with Borated Water Leakage</u>. In LRA Table 3.3.2-12, the applicant stated that ceramic fiber insulation and

wraps, mineral fiber insulation and wraps, and mineral fiber structural steel fireproofing exposed to uncontrolled indoor air or air with borated water leakage have no aging effect. The AMR items cite generic note F and plant-specific notes 4 or 5, which state that based on plant OE there are no AERM for these materials and environments. The plant-specific notes 4 and 5 further state that the materials do not experience aging effects unless exposed to temperatures, radiation, or chemicals capable of attacking the specific chemical composition, and that environments are nonaggressive; therefore, the materials are not expected to experience significant aging effects. Nonetheless, the Fire Protection program is credited for ensuring the absence of any aging effects.

The staff reviewed the associated items in the LRA and considered whether there are any aging effects that should be managed by the applicant for this component, material, and environment description. Although the GALL Report does not include any AMR items for nonmetallic fire barriers, the staff noticed that GALL Report AMP XI.M26, "Fire Protection," does include aging management activities for "other" fire resistant materials that serve a fire barrier function that are within the "scope of program." GALL Report AMP XI.M26 recommends that these materials be managed for loss of material. Although the applicant has stated that there are no aging effects, it has also stated that it will employ the Fire Protection program to ensure the absence of the aging effects. The Fire Protection program includes visual inspections of fire barrier materials on a refuel cycle frequency.

The staff's evaluation of the applicant's Fire Protection program is documented in SER Section 3.0.3.2.10. The applicant inspects fire resistant insulations and wraps as part of the fire-rated assembly inspections for signs of degradation such as physical damage and loose or missing parts. It also inspects the fireproofing for structural steel as part of the fire-rated assembly visual inspections and as part of the weekly fire marshal tours for signs of age-related degradation that could lead to loss of function due to excessive exposed metal. The staff finds the applicant's proposal to verify the absence of aging effects using the Fire Protection program acceptable because the inspection methods employed will be capable of detecting any signs of degradation.

<u>Gypsum and Pyrocrete Fire Barriers Exposed to Uncontrolled Indoor Air or Air with Borated Water Leakage</u>. In LRA Table 3.3.2-12, the applicant stated that gypsum and Pyrocrete fire barriers (i.e., used in walls, ceilings, floors, and penetration seals, and as structural steel fire proofing) exposed to uncontrolled indoor air or air with borated water leakage will be managed for cracking, loss of material and loss of bond by the Fire Protection program. The AMR items cite generic Note F and plant-specific Note 8, which state that the Fire Protection program will be used to manage the listed aging effects.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Although the GALL Report does not include any AMR items for nonmetallic fire barriers, the staff noticed that GALL Report AMP XI.M26, "Fire Protection," does include aging management activities for fire resistant materials, including spray-on fireproofing, that are within the "scope of program." GALL Report AMP XI.M26 recommends that these materials be managed for signs of degradation such as loss of material, cracking, and spalling. Based on its review of the GALL Report, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Fire Protection program is documented in SER Section 3.0.3.2.10. The applicant visually inspects fire-rated assemblies (i.e., fire barrier walls, ceilings, and floors) for signs of age-related degradation. It also inspects the fireproofing for structural steel as part of the fire-rated assembly visual inspections and as part of the weekly fire marshal tours for signs of age-related degradation that could lead to loss of function due to excessive exposed metal. The staff finds the applicant's proposal to manage the effects of aging the Fire Protection program acceptable because the inspection methods employed will be capable of detecting any signs of degradation.

Carbon Steel Fire Barriers (penetration seals) Exposed to Uncontrolled Indoor Air. By letter dated May 23, 2014, Exelon amended LRA Table 3.3.2-12 to include AMR items for carbon penetration seals externally exposed to uncontrolled indoor air. Exelon stated that it will manage the penetration seals for loss of material using the Fire Protection program. The AMR item cites generic Note F and plant-specific Note 14, which states that the Fire Protection program will be used to manage the applicable aging effect.

The staff reviewed the associated item in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. Principles and Prevention of Corrosion, 2nd Edition (D. Jones, Prentice Hall, 2005) states that cracking of carbon steels is a concern when exposed to hot caustic (e.g., sodium hydroxide) and nitrate solutions, as well as other environments typically associated with the chemical processing industry, such as sulfuric acid, liquid ammonia, and cyanides. The carbon steel penetration seals are not exposed to these types of environments; therefore, cracking is not an aging effect of concern. Based on its review of aforementioned reference, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Fire Protection program is documented in SER Section 3.0.3.2.10. The Fire Protection program manages loss of material, among other aging effects, through periodic visual inspection of components and structures with a fire barrier intended function. Visual inspections of fire barriers are performed on a refueling cycle frequency. The staff finds the applicant's proposal to manage loss of material using the Fire Protection program acceptable because the program includes visual inspections that are capable of detecting degradation of fire penetration seals.

Carbon Steel and Stainless Steel Piping Exposed to Diesel Exhaust. In LRA Table 3.3.2-12, the applicant stated that carbon steel and SS piping exposed to diesel exhaust (internal) will be managed for cumulative fatigue damage by a TLAA. The AMR items cite generic Note H, which states that the TLAA is evaluated in LRA Section 4.3. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3, for this component and material. The staff's evaluation of the fatigue TLAA for the fire protection system is documented in SER Section 4.3.

Carbon Steel and Stainless Steel Insulated Piping Exposed to Diesel Exhaust. In LRA Table 3.3.2-12, the applicant stated that carbon steel and SS piping exposed to diesel exhaust (internal) will be managed for cumulative fatigue damage by a TLAA. The AMR items cite generic Note H, which states that the TLAA is evaluated in LRA Section 4.3. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3, for this component and material. The staff's evaluation of the fatigue TLAA for the fire protection system is documented in SER Section 4.3.

Soil, Rip-Rap, Sand, and Gravel Earthen Water-Control Structures (fuel oil storage tank berm) Exposed to Air-Outdoor (external). In LRA Table 3.3.2-12, the applicant stated that soil, rip-rap, sand, and gravel earthen water-control structures (fuel oil storage tank berm) exposed to air-outdoor (external) will be managed for loss of material or loss of form by the Structures Monitoring Program. The AMR item cites generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of *Fundamentals of Soil Behavior* (Mitchell and Soga, 2005) which states that "…wind…and gravity continually erode and transport soil and rock debris away from the zone of weathering," the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because the scope of the Structures Monitoring Program has been enhanced to include fire protection structures-features, which includes the fuel oil storage tank berm, and because the periodic visual inspections performed under the Structures Monitoring Program would be capable of detecting a gross loss of material or loss of form.

Stainless Steel Bolting Exposed to Raw Water. The staff's evaluation for SS bolting exposed to raw water, which will be managed for loss of material by the Bolting Integrity Program and is associated with generic Note H, is documented in SER Section 3.3.2.3.10.

Carbon Steel Tank with Internal Coating or Lining Exposed to Raw Water. In LRA Table 3.3.2-12, as revised by letter dated January 13, 2014, the applicant stated that the carbon steel foam concentrate storage tank with internal coating or lining exposed to raw water will be managed for loss of coating integrity by the Fire Water System program. The AMR item cites generic Note H.

The staff's evaluation of the applicant's Fire Water System program is documented in SER Section 3.0.3.2.11. In addition, the staff's evaluation of how the applicant is going to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage for coatings that have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks) is documented in SER Section 3.0.3.3.1. The staff finds the applicant's proposal to manage loss of coating integrity for the foam concentrate storage using the Fire Water System program acceptable because the program uses periodic visual examinations, every 10 years, of the tank's coating which are capable of detecting loss of coating integrity. The staff finds the applicant's proposal to manage loss of coating integrity for the foam concentrate storage tanks using the Fire Water System program acceptable because the program includes periodic visual inspections capable of detecting loss of coating integrity of the coatings by qualified individuals.

Copper Alloy with Less than 15 Percent Zinc Bolting Exposed to Raw Water. In LRA Table 3.3.2-12, as revised by letter dated July 18, 2014, the applicant stated that copper alloy with less than 15 percent zinc bolting (Braidwood only) exposed to raw water will be managed for loss of material by the Bolting Integrity program. The AMR item cites generic Note H and plant-specific Note 16, which state that inspections of the bolting are performed in conjunction with maintenance activities.

The staff found that this material and environment combination is identified in the GALL Report, which states that copper-alloy bolting exposed to any environment is susceptible to loss of preload and recommends GALL Report AMP XI.M18, “Bolting Integrity,” to manage the aging effects. However the applicant has identified loss of material as an additional aging effect. The applicant addressed the GALL Report identified aging effect for this component, material and environment combination in another AMR item in LRA Table 3.3.2-12.

The staff noticed that the subject bolting is associated with travelling screens for the fire pump suction water supply at Braidwood Station and has a structural function. The staff also noticed that the applicant’s Bolting Integrity Program, as described in the LRA, does not manage the aging of structural bolting. LRA Section B.2.1.9 states that the Bolting Integrity Program addresses closure bolting on pressure retaining joints and that the aging of structural bolting is managed by either the ASME Section XI, Subsection IWF program, Structures Monitoring program, or the R.G. 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants program. Therefore, in a telephone conference call on July 30, 2014, the staff requested that the applicant clarify the function of the bolting and describe the method and frequency of inspections that will be used to manage loss of material.

In its letter dated August 29, 2014, the applicant stated that the bolting attaches a series of mesh baskets to a chain for online debris removal. The applicant also stated that each bolt is visually inspected at least once every 6 years to verify that it is secure, opportunistic inspections of bolt threads are performed during maintenance activities, and annual diver inspections jog the travelling screen through a cycle and visually inspect each bolt. The staff noticed that the use of divers to periodically inspect the travelling screens is documented in the applicant’s Fire Water System program documents in LRA Sections A.2.1.16 and B.2.1.16.

The staff’s evaluation of the applicant’s Bolting Integrity Program is documented in SER Section 3.0.3.2.4. As described above, the applicant proposes to use the Bolting Integrity Program to manage loss of material of the copper structural bolting associated with the travelling screen baskets through periodic and opportunistic visual inspections and monitoring of the performance of the screens as they are jogged through a cycle. The staff finds the applicant’s proposal to manage loss of material using the Bolting Integrity Program acceptable because the periodic verification of performance of the bolting (e.g., maintenance of a secure connection and proper operation of the traveling screens) and visual inspections of the bolt heads and threads are capable of identifying loss of material prior to loss of intended function.

The staff concludes for items in LRA Table 3.3.2-12 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.13 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 identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the fresh water system component groups are consistent with the GALL Report.

3.3.2.3.14 Fuel Handling & 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. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the fuel handling and fuel storage system component groups are consistent with the GALL Report.

3.3.2.3.15 Fuel Oil System—Summary of Aging Management Evaluation—LRA Table 3.3.2-15

Carbon Steel Tanks with Internal Coating or Lining Exposed to Raw Water. In LRA Table 3.3.2-15, as revised by letter dated January 13, 2014, the applicant stated that the carbon steel DG fuel oil storage tanks with internal coating or lining exposed to fuel oil will be managed for loss of coating integrity by the Fuel Oil Chemistry program. The AMR item cites generic Note H.

The staff's evaluation of the applicant's Fuel Oil Chemistry program is documented in SER Section 3.0.3.2.13. In addition, the staff's evaluation of how the applicant's changes to the Fuel Oil Chemistry program to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage for coatings that have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks) is documented in SER Section 3.0.3.3.1. The staff finds the applicant's proposal to manage loss of coating integrity for the DG fuel oil storage tanks using the Fuel Oil Chemistry program acceptable because the program includes periodic visual inspections capable of detecting loss of coating integrity of the coatings by qualified individuals.

The staff concludes for items in LRA Table 3.3.2-15 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.16 Heating Water and Heating Steam 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 heating water and heating steam system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the heating water and heating steam system component groups are consistent with the GALL Report.

3.3.2.3.17 Nonradioactive Drain 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 nonradioactive drain system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the nonradioactive drain system component groups are consistent with the GALL Report.

3.3.2.3.18 Radiation Monitoring 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 AMR evaluations for the radiation monitoring system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the radiation monitoring system component groups are consistent with the GALL Report.

3.3.2.3.19 Radioactive Drain System—Summary of Aging Management Evaluation—LRA Table 3.3.2-19

<u>Stainless Steel Piping Components Exposed Internally to Waste Water Greater than 60 °C (140 °F)</u>. In LRA Tables 3.3.2-19 and 3.3.2-21, the applicant stated that SS piping, piping components, piping elements, pump casing, restricting orifices, tanks, and valve bodies exposed internally to waste water greater than 60 °C (140 °F) will be managed for cracking by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that the applicant addressed loss of material for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-19 and 3.3.2-21. Based on its review of the GALL Report, which states that 60 °C (140 °F) is the SCC threshold for SS, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections for corrosion to detect cracking of metallic components. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage the effects of aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections capable of detecting cracking.

The staff concludes for items in LRA Table 3.3.2-19 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.20 Radwaste System—Summary of Aging Management Evaluation—LRA Table 3.3.2-20

<u>Gray Cast Iron Valve Bodies Exposed to Waste Water</u>. In LRA Table 3.3.2-20, the applicant stated that gray cast iron valve bodies internally exposed to waste water will be managed for loss of material by the Selective Leaching program. The AMR item cites generic Note G, and plant-specific Note 2, which state that selection of the Selective Leaching program is based on other GALL Report items for gray cast iron in similar environments, such as VII.H2.A-51.

The staff reviewed the associated item in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that the applicant addressed loss of material (due to general, pitting, crevice, and microbiologically-influenced corrosion) for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-20. Based on its review of the GALL Report, which states that steel (including gray cast iron) is vulnerable to general, pitting, and crevice corrosion, and that gray cast iron is susceptible to selective leaching, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Selective Leaching program is documented in SER Section 3.0.3.1.7. The applicant's Selective Leaching program manages loss of material in copper-alloy (greater than 15 percent copper) and gray cast iron components exposed to various water environments or outdoor air (Byron only) by conducting a one-time visual inspection, supplemented by hardness or other examination method, of selected components to determine whether selective leaching is occurring. The staff finds the applicant's proposal to manage loss of material using the Selective Leaching program acceptable because a visual inspection coupled with hardness measurement or appropriate examination technique is capable of detecting if a loss of material due to selective leaching is occurring in gray cast iron components.

<u>Titanium Clad Carbon or Low-Alloy Steel Heat Exchanger Tubes Exposed to Waste Water</u>. In LRA Table 3.3.2-20, the applicant stated that, for titanium clad carbon or LAS heat exchanger tubes exposed to waste water, there is no aging effect and that no AMP is proposed. The AMR item cites generic Note G and cites a plant-specific Note 1 stating that the selection of no aging effect is based on other GALL Report items, such as VII.C1.AP-152, for titanium in similar environments.

The staff reviewed the associated item in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff notes that AMR item VII.C1.AP-152, as discussed in NUREG-1950, states that loss of material due to corrosion is not considered applicable for titanium because the continuous, stable, and highly adherent oxide layer makes it fully corrosion resistant in raw water. In addition, this AMR item states that SCC is only applicable in sea water or brackish water environments, which are not considered as part of the waste water environment specified in LRA Table 3.0-1, "Byron and Braidwood Service Environments." Based on the above, the staff finds the applicant's determination of no aging effect for these components acceptable.

<u>Carbon Steel Components with Internal Coating or Lining Exposed to Waste Water</u>. In LRA Tables 3.3.2-20 and 3.3.2-22, as revised by letter dated January 13, 2014, the applicant stated that the carbon steel piping, piping components, piping elements, tanks, valves, and heat exchangers with internal coating or lining exposed to waste water will be managed for loss of coating integrity by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic Note H.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. In addition, the staff's evaluation of how the applicant is going to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage for coatings that have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks) is documented in SER Section 3.0.3.3.1. The staff noticed that the subject components are associated with the caustic and acid supply to the rad waste system demineralizers; however, these components are not in service and not exposed to the aggressive environment for which the coating was required. The staff noticed that, given that the systems are isolated, in-leakage to the system would have a similar environmental impact as waste water as defined in GALL Report Section IX.D (waters that are collected from equipment and floor drains). The staff finds the applicant's proposal to manage loss of coating integrity for these components using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because: (a) the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is recommended by GALL Report item AP-281 to manage loss of material for steel components exposed to waste water, (b) the likelihood of accelerated corrosion is low because there are no corrosive chemicals in the environment and no significant galvanic couples, (c) flow blockage affecting active systems is not possible because the applicable portions of the system are isolated from active systems, and (d) periodic internal visual inspections will occur that are capable of detecting loss of material and loss of coating integrity.

The staff concludes for items in LRA Table 3.3.2-20 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.21 Sampling System—Summary of Aging Management Evaluation—LRA Table 3.3.2-21

Copper Alloy with 15 Percent or More Zinc Valve Bodies Exposed to Closed-Cycle Cooling Water. The staff's evaluation for copper-alloy with 15 percent or more zinc valve bodies exposed to closed-cycle cooling water, which will be managed for cracking by the Closed Treated Water Systems Program and are associated with generic Note H, is documented in SER Section 3.3.2.3.11.

Stainless Steel Piping Components Exposed Internally to Waste Water Greater than 60 °C (140 °F). The staff's evaluation for SS piping, piping components, piping elements, pump casing, restricting orifices, tanks, and valve bodies exposed internally to waste water greater than 60 °C (140 °F), which will be managed for cracking by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and are associated with generic Note G, is documented in SER Section 3.3.2.3.19.

The staff concludes for items in LRA Table 3.3.2-21 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.22 Service Water System—Summary of Aging Management Evaluation—LRA Table 3.3.2-22

Carbon Steel and Stainless Steel Piping Exposed to Diesel Exhaust. In LRA Table 3.3.2-22, the applicant stated that carbon steel and SS piping exposed to diesel exhaust (internal) will be managed for cumulative fatigue damage by a TLAA. The AMR items cite generic Note H, which states that the TLAA is evaluated in LRA Section 4.3. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3, for this component and material. The staff's evaluation of the fatigue TLAA for the service water system is documented in SER Section 4.3.

Gray Cast Iron Gear Box Exposed to Outdoor Air (Byron only). In LRA Table 3.3.2-22, the applicant stated that gray cast iron gear box externally exposed to outdoor air will be managed for loss of material by the Selective Leaching program. The AMR item cites generic Note H and plant-specific Note 2, which state that selection of the Selective Leaching program is based on other GALL Report items for gray cast iron in similar environments, such as VII.H2.A-51.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that steel heat exchanger components externally exposed to outdoor air are susceptible to loss of material due to general, pitting, and crevice corrosion and recommends GALL Report AMP XI.M36 to manage the aging effect. However, the applicant has identified loss of material due to selective leaching as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.3.2-22.

The staff's evaluation of the applicant's Selective Leaching program is documented in SER Section 3.0.3.1.7. The applicant's Selective Leaching program manages loss of material in copper-alloy (greater than 15 percent copper) and gray cast iron components exposed to various water environments or outdoor air (Byron only) by conducting a one-time visual inspection, supplemented by hardness or other examination method, of selected components to determine whether selective leaching is occurring. The staff finds the applicant's proposal to manage loss of material using the Selective Leaching program acceptable because a visual inspection coupled with hardness measurement or appropriate examination technique is capable of detecting if a loss of material due to selective leaching is occurring in gray cast iron components.

Polymeric Piping, Piping Subcomponents, and Piping Elements Exposed to Raw Water. In LRA Table 3.3.2-22, the applicant stated that for polymeric piping, piping subcomponents, and piping elements exposed to raw water, there is no aging effect and that no AMP is proposed. The AMR item cites generic Note G. The AMR item cites plant-specific note 3, which states:

> Based on plant operating experience, there are no aging effects requiring management for the polymer piping in a raw water environment. This material does not experience aging effects unless exposed to elevated temperatures or radiation levels capable of attacking the specific chemical composition. The material in this water environment is not expected to experience significant aging effects due to elevated temperatures or radiation levels. The first pipe material is Bristol Pipe PVC 1120, which is installed on the corrosion monitoring skid at Braidwood Only. The primary chemical at this point in the system is sodium hypochlorite, which is maintained at a concentration of less than 1 ppm free available chlorine. The second pipe material is Kynar® PVDF (polyvinylidene fluoride) for the chemical feed piping at both Byron and Braidwood sites. The primary chemical in this system is also sodium hypochlorite, which has a concentration of approximately 15 percent.

The staff reviewed the associated item in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination.

PVC Pipe Installed at Braidwood Only. The staff noticed that "PVC Pipe – Design and Installation – Manual of Water Supply Practices," M23, American Water Works Association, Second Edition, 2002, states: "PVC and PVCO pipes are resistant to almost all types of corrosion—both chemical and electrochemical—that are experienced in underground piping systems. Because PVC is a nonconductor, galvanic and electrochemical effects are nonexistent in PVC piping systems. PVC pipe cannot be damaged by aggressive waters or corrosive soils." It also states: "PVC pipe is nearly totally resistant to biological attack. Biological attack can be described as degradation or deterioration caused by the action of living microorganisms or macroorganisms." It further states that "PVC pipe is well suited to applications where abrasive conditions are anticipated."

Appendix A, Chemical Resistance Tables of this document, lists PVC as generally resistant to chemicals up to 140 °F (60 °C), such as bleach (12.5 percent active chlorine), potassium hydroxide, sodium hydroxide, kerosene, hydrochloric acid, hydrogen peroxide (90 percent), sea water, soaps, and sulfuric acid (70 percent). The staff noticed that "PVC Formulary," G. Wypych, ChemTec Publishing, 2009 states, "[a]s a general rule, PVC is not resistant to polar solvents but very resistant to acids, bases, salts, alcohols, esters, and hydrocarbons."

The staff finds the applicant's proposal acceptable based on its review of the above documents because PVC pipe is resistant to the raw water that would be present in the service water piping including hypochlorite, which is maintained at a concentration of less than 1 ppm free available chlorine.

Kynar Polyvinylidene Fluoride (PVDF) for the Chemical Feed Piping at Both Byron and Braidwood Sites. The staff noticed that the EPRI "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools Technical Report," Revision 4, states that PVDF is highly corrosion resistant and shows no effect in acids or alkalis; is resistant to strong acids and organic solvents, and, has a continuous heat resistance of 300 °F. The staff also noticed that "Hawley's Condensed Chemical Dictionary," Richard J. Lewis, Sr., John Wiley & Sons, 2007, describes polyvinylidene fluoride as, "[i]n film form it is characterized by superior resistance to weather, high strength, high dielectric constant, low permeability to air and water, as well as oil, chemical solvent, and stain resistance." The staff further noticed that the website http://www.porex.com/technologies/materials/porous-plastics/polyvinylidene-fluoride/, a supplier of PVDF material, states that "[p]olyvinylidene fluoride (PVDF) is a fluorocarbon and is classified as 'Self Extinguishing, Group 1' by Underwriters' Laboratories, Inc. It is unaffected by long-term exposure to sunlight and other sources of ultraviolet radiation. It retains its properties in high vacuum and gamma radiation and is resistant to most acids and alkalis. PVDF is the material of choice when the porous structure will be exposed to ozone or chlorine." Another supplier website, http://www.omega.com/pdf/tubing/fittings_tubing_hose/nylon_poly_kynar/nylon.asp, states: "KYNAR has been used as a pipe liner in chemical processing plants since its introduction nearly 30 years ago. It has been used extensively in the paper and paper pulp industries, where equipment is constantly exposed to high concentrations of Chlorine and [Chlorine] Dioxide. In these applications the permeation resistance of KYNAR components far surpassed that of PTFE."

The staff finds the applicant's proposal acceptable based on its review of the above documents because PVDF pipe is resistant to the raw water that would be present in the service water piping including chlorine.

Stainless Steel Bolting Exposed to Raw Water. The staff's evaluation for SS bolting exposed to raw water, which will be managed for loss of material by the Bolting Integrity Program and is associated with generic Note H, is documented in SER Section 3.3.2.3.10.

Carbon Steel, Stainless Steel, and Copper Alloy with Greater than 15 Percent Zinc Heat Exchangers with Internal Coating or Lining Exposed to Raw Water. In LRA Tables 3.3.2-22 and 3.4.2-1, as revised by letter dated January 13, 2014, the applicant stated that carbon steel, SS, and copper-alloy with greater than 15 percent zinc heat exchangers with internal coating or lining exposed to raw water will be managed for loss of coating integrity by the Open-Cycle Cooling Water System Program. The AMR items cite generic Note H.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.2.6. In addition, the staff's evaluation of how the applicant is going to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage for coatings that have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks) is documented in SER Section 3.0.3.3.1. The staff finds the applicant's proposal to manage loss of coating integrity for the DG fuel oil storage tanks using the Open-Cycle Cooling Water System program acceptable because the program includes periodic visual inspections capable of detecting loss of coating integrity of the coatings by qualified individuals.

Carbon Steel Components with Internal Coating or Lining Exposed to Waste Water. The staff's evaluation for carbon steel piping, piping components, piping elements, valves, and heat exchangers with internal coating or lining exposed to waste water, which will be managed for loss of coating integrity by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and is associated with generic Note H, is documented in SER Section 3.3.2.3.20.

The staff concludes for items in LRA Table 3.3.2-22 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.3.2.3.23 Spent Fuel Cooling 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 spent fuel cooling system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the spent fuel cooling system component groups are consistent with the GALL Report.

3.3.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4 Aging Management of Steam and Power Conversion Systems

This 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 systems:

- auxiliary feedwater system
- condensate and feedwater auxiliaries system
- main condensate and feedwater 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. LRA Table 3.4.1, "Summary of Aging Management Evaluations for the Steam and Power Conversion System," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the steam and power conversion system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry OE 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 OE included a review of the GALL Report and OE issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

Table 3.4-1 summarizes the staff's evaluation of components, aging effects, or mechanisms, and AMPs listed in LRA Section 3.4 and addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-1)	Cumulative fatigue damage due to fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation. See the SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.4.2.2.1)
Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor (3.4.1-2)	Cracking due to SCC	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report (see SER subsection 3.4.2.2.2)
Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor (3.4.1-3)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report (see SER subsection 3.4.2.2.3)
Steel external surfaces, bolting exposed to air with borated water leakage (3.4.1-4)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to steam, treated water (3.4.1-5)	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Flow-Accelerated Corrosion Program	Consistent with the GALL Report
Steel, stainless steel bolting exposed to soil (3.4.1-6)	Loss of preload	Chapter XI.M18, "Bolting Integrity "	No	Bolting Integrity Program	Consistent with the GALL Report
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-7)	Cracking due to cyclic loading, SCC	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel bolting, closure bolting exposed to air – outdoor (external), air – indoor, uncontrolled (external) (3.4.1-8)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program	Consistent with the GALL Report
Steel closure bolting exposed to air with steam or water leakage (3.4.1-9)	Loss of material due to general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Byron and Braidwood
Copper alloy, nickel alloy, steel; stainless steel, steel; stainless steel bolting, closure bolting exposed to any environment, air – outdoor (external), air – indoor, uncontrolled (external) (3.4.1-10)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity Program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements, tanks, heat exchanger components exposed to steam, treated water >60 °C (>140 °F) (3.4.1-11)	Cracking due to SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report
Steel; stainless steel tanks exposed to treated water (3.4.1-12)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to treated water (3.4.1-13)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements, PWR heat exchanger components exposed to steam, treated water (3.4.1-14)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report
Steel heat exchanger components exposed to treated water (3.4.1-15)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report
Copper alloy, stainless steel, nickel alloy, aluminum piping, piping components, and piping elements, heat exchanger components and tubes, PWR heat exchanger components exposed to treated water, steam (3.4.1-16)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report
Copper alloy heat exchanger tubes exposed to treated water (3.4.1-17)	Reduction of heat transfer due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood
Copper alloy, stainless steel heat exchanger tubes exposed to treated water (3.4.1-18)	Reduction of heat transfer due to fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel heat exchanger components exposed to raw water (3.4.1-19)	Loss of material due to general, pitting, crevice, galvanic, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Copper alloy, stainless steel piping, piping components, and piping elements exposed to raw water (3.4.1-20)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Stainless steel heat exchanger components exposed to raw water (3.4.1-21)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Stainless steel, copper-alloy, steel heat exchanger tubes, heat exchanger components exposed to raw water (3.4.1-22)	Reduction of heat transfer due to fouling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Open-Cycle Cooling Water System Program	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)	Cracking due to SCC	Chapter XI.M21A, “Closed Treated Water Systems”	No		Not applicable to Byron and Braidwood
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-24)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No		Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-25)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-26)	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-27)	Loss of material due to pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Steel, stainless steel, copper-alloy heat exchanger components and tubes, heat exchanger tubes exposed to closed-cycle cooling water (3.4.1-28)	Reduction of heat transfer due to fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems Program	Consistent with the GALL Report
Steel tanks exposed to air – outdoor (external) (3.4.1-29)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Steel, stainless steel, aluminum tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to soil or concrete, or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation (3.4.1-30)	Loss of material due to general (steel only), pitting, and crevice corrosion; cracking due to SCC (stainless steel and aluminum only)	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks program Exceptions apply to Aboveground Metallic Tanks program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, aluminum tanks exposed to soil or concrete (3.4.1-31)	Loss of material due to pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks program Exceptions apply to Aboveground Metallic Tanks program	Consistent with the GALL Report
Gray cast iron piping, piping components, and piping elements exposed to soil (3.4.1-32)	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to Byron and Braidwood
Gray cast iron, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements exposed to treated water, raw water, closed-cycle cooling water (3.4.1-33)	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching program	Consistent with the GALL Report
Steel external surfaces exposed to air – indoor, uncontrolled (external), air – outdoor (external), condensation (external) (3.4.1-34)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to air – outdoor (3.4.1-35)	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air – outdoor (internal) (3.4.1-36)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to condensation (internal) (3.4.1-37)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-38)	Loss of material due to general, pitting, crevice, galvanic, and microbi-ologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to condensation (internal) (3.4.1-39)	Loss of material due to pitting and crevice corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to lubricating oil (3.4.1-40)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report
Steel heat exchanger components exposed to lubricating oil (3.4.1-41)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum piping, piping components, and piping elements exposed to lubricating oil (3.4.1-42)	Loss of material due to pitting and crevice corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Lubricating Oil Analysis program, One-Time Inspection Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	Consistent with the GALL Report
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.4.1-43)	Loss of material due to pitting and crevice corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements, heat exchanger components exposed to lubricating oil (3.4.1-44)	Loss of material due to pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report
Aluminum heat exchanger components and tubes exposed to lubricating oil (3.4.1-45)	Reduction of heat transfer due to fouling	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to Byron and Braidwood
Stainless steel, steel, copper-alloy heat exchanger tubes exposed to lubricating oil (3.4.1-46)	Reduction of heat transfer due to fouling	Chapter XI.M39, “Lubricating Oil Analysis,” and Chapter XI.M32, “One-Time Inspection”	No	Lubricating Oil Analysis program and One-Time Inspection Program	Consistent with the GALL Report
Steel (with coating or wrapping) piping, piping components, and piping elements; tanks exposed to soil or concrete (3.4.1-47)	Loss of material due to general, pitting, crevice, and microbi-ologically influenced corrosion	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel bolting exposed to soil (3.4.1-48)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.4.1-49)	Loss of material due to pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks program Exceptions apply to Buried and Underground Piping and Tanks program	Consistent with the GALL Report
Steel bolting exposed to soil (3.4.1-50)	Loss of material due to general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Underground stainless steel and steel piping, piping components, and piping elements (3.4.1-50x)	Loss of material due to general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Byron and Braidwood
Steel piping, piping components, and piping elements exposed to concrete (3.4.1-51)	None	None, provided (1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557, and (2) plant OE indicates no degradation of the concrete	No, if conditions are met	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum piping, piping components, and piping elements exposed to gas, air – indoor, uncontrolled (internal/external) (3.4.1-52)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Copper alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.4.1-53)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Copper alloy piping, piping components, and piping elements exposed to gas, air – indoor, uncontrolled (external) (3.4.1-54)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Glass piping elements exposed to lubricating oil, air – outdoor, condensation (internal/external), raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water, air – indoor, uncontrolled (external) (3.4.1-55)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Nickel alloy piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external) (3.4.1-56)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy, PVC piping, piping components, and piping elements exposed to air with borated water leakage, air – indoor, uncontrolled, condensation (internal) (3.4.1-57)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Byron and Braidwood
Stainless steel piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external), concrete, gas, air – indoor, uncontrolled (internal) (3.4.1-58)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air – indoor controlled (external), gas (3.4.1-59)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report
Insulated steel, stainless steel, copper alloy, aluminum, or copper alloy (> 15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor (3.4.1-63)	Loss of material due to general (steel, and copper alloy), pitting, or crevice corrosion, and cracking due to stress corrosion cracking (aluminum, stainless steel and copper alloy (>15% Zn) only)	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components” or Chapter XI.M29, “Aboveground Metallic Tanks” (for tanks only)	No	One-Time Inspection Program	Consistent with the GALL Report
Jacketed calcium silicate or fiberglass insulation in an air-indoor uncontrolled or air-outdoor environment (3.4.1-64)	Reduced thermal insulation resistance due to moisture intrusion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	One-Time Inspection Program	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Jacketed foamglas® (glassdust) insulation in an air-indoor uncontrolled or air-outdoor environment (3.4.1-65)	Reduced thermal insulation resistance due to moisture intrusion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components program	Not applicable to Byron and Braidwood

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 that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.4.2.2, discusses the staff's review of AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.4.2.3, discusses the staff's review of AMR results for components that the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.4.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the steam and power conversion systems components:

- Aboveground Metallic Tanks
- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping
- Closed Treated Water Systems
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Fuel Oil Chemistry
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Open-Cycle Cooling Water System
- Selective Leaching
- TLAA
- Water Chemistry

LRA Tables 3.4.2-1 through 3.4.2-5 summarize the AMRs for the steam and power conversion 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 claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if 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 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–E, which indicate how the AMR was consistent with the GALL Report.

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

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these items to confirm 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 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. Note C 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 items to confirm consistency with the GALL Report and determined whether the AMR 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 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 items to confirm consistency with the GALL Report and confirmed whether the AMR 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these AMR items to confirm 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, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

3.4.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.4.1, items 3.4.1-7, 3.4.1-9, 3.4.1-17, 3.4.1-18, 3.4.1-23, 3.4.1-24, 3.4.1-29, 3.4.1-32, 3.4.1-36, 3.4.1-45, 3.4.1-50, 3.4.1-50x, 3.4.1-51, 3.4.1-53, 3.4.1-56, and 3.4.1-57, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at BBS. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.4.1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff nonapplicability verification of these items required the review of sources beyond the LRA and UFSAR, and/or the issuance of RAIs.

3.4.2.1.2 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion

(Braidwood Only) LRA Table 3.4.1, item 3.4.1-42 addresses aluminum alloy heater well exposed to lubricating oil internally, which will be managed for loss of material. For the AMR item that cites generic Note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effect for aluminum alloy heater well. The GALL Report recommends GALL Report AMP XI.M39, "Lubricating Oil Analysis," and XI.M32, "One-Time Inspection" to ensure that this aging effect is adequately managed. GALL Report AMP XI.M39 recommends maintaining oil system contaminants within acceptable limits through periodic sampling and analysis, and comparing the analytical results to predetermined limits that are associated with corrective actions such as filtering or oil replacement in order to manage the aging effects of loss of material due to corrosion or reduction of heat transfer due to fouling. Additionally, the One-Time Inspection Program will be used to verify that the effectiveness of the Lubricating Oil analysis program is designed to prevent or minimize age-related degradation.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that the Internal Surfaces in Miscellaneous Piping and Ducting Components proposes to manage the aging of aluminum heater wells through the use of opportunistic visual inspections of the internal surfaces of piping and components during periodic surveillances or maintenance activities when the surfaces are accessible for visual inspection. Based on its review of components associated with item 3.4.1-42 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the oil in the heater well is used to transfer heat from the heating element and is not used as a lubricating medium. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses visual inspection and is capable of detecting loss of material for this component.

The staff concludes that for LRA item 3.4.1-42 the applicant 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 Cracking Due to Stress Corrosion Cracking

The staff's evaluation for Table 3.4-1, item 3.4.1-63, which addresses cracking insulated SS and aluminum piping, piping components, and piping elements externally exposed to outdoor air, is documented in SER Section 3.2.2.1.3.

3.4.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.4.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the steam and power conversion systems components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- cracking due to SCC
- loss of material due to pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.4.2.2. The staff's review of the applicant's further evaluation follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1, which is associated with LRA Table 3.4.1, item 3.4.1-1, addresses steel piping, piping components, and piping elements exposed to steam or treated water in the steam and power conversion system that are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Sections 4.3 and 4.7.

The staff reviewed LRA Section 3.4.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.1, which states that fatigue of steam and power conversion system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1). The staff reviewed the applicant's AMR line items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel piping, piping components, and piping elements exposed to steam or treated water.

The staff concludes that the applicant has met the SRP-LR Section 3.4.2.2.1 criteria. For those line items that apply to LRA Section 3.4.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant demonstrated that it will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Sections 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAA for these components.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking (SCC)

As revised by letter dated January 13, 2014, LRA Section 3.4.2.2.2, associated with LRA Table 3.4.1, item 3.4.1-2, addresses SS piping, piping components, piping elements, and tanks exposed to outdoor air, which will be managed for cracking due to SCC by the External Surfaces Monitoring of Mechanical Components Program. The criterion in SRP-LR Section 3.4.2.2.2 states that cracking due to SCC could occur for SS piping, piping components, piping elements and tanks exposed to outdoor air in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. The GALL Report recommends further evaluation to determine whether an AMP is needed to manage this aging effect based on the environmental conditions applicable to the plant and requirements applicable to the components. The SRP-LR also states that GALL AMP XI.M36, "External Surface Monitoring of Mechanical Components," is an acceptable method to manage cracking due to SCC. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the External Surfaces Monitoring of Mechanical Components Program will be used to manage cracking of SS components exposed to outdoor air in the main condensate and feedwater system.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.9. In its review of components associated with item 3.4.1-2, the staff finds that the applicant has met the further evaluation criteria. The applicant's proposal to manage the effects of aging using the External Surfaces Monitoring of Mechanical Components Program is acceptable because the program includes periodic visual inspections of piping and piping components for leakage at least once per refueling cycle, which will be capable of detecting cracking due to SCC prior to loss of intended function.

Based on the program identified, the staff determines that the applicant's program meets SRP-LR Section 3.4.2.2.2 criteria. For those items associated with LRA Section 3.4.2.2.2, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Section 3.4.2.2.3, associated with LRA Table 3.4.1 item 3.4.1-3, addresses SS piping, piping components, piping elements, and tanks exposed to outdoor air which will be managed for loss of material due to pitting and crevice corrosion by the External Surfaces Monitoring of Mechanical Components Program. The criteria in SRP-LR Section 3.4.2.2.3, item 1, state that loss of material due to pitting and crevice corrosion could occur for SS piping, piping components, piping elements, and tanks exposed to outdoor air. The SRP-LR also states that the possibility of pitting and crevice corrosion also extends to components exposed to air that has been recently introduced into the building (i.e., components near intake vents). The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material in SS piping, piping components, and piping elements will be managed by the External Surfaces Monitoring of Mechanical Components Program.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.9. In its review of components associated with item 3.4.1-3, the staff finds that the applicant has met the further evaluation criteria. The applicant's proposal to manage the effects of aging using the External Surfaces Monitoring of Mechanical Components Program is acceptable because the AMP provides for management of loss of material through visual inspections of external surfaces at least once per refueling outage, which are capable of detecting corrosion prior to loss of intended function.

Based on the program identified, the staff determines that the applicant's program meets SRP-LR Section 3.4.2.2.3 criteria. For those items associated with LRA Section 3.4.2.2.3, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.4.2.2.5 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of OE of AMPs.

3.4.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-5, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.4.2-1 through 3.4.2-5, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR 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 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. The staff's evaluation is discussed in the following sections.

3.4.2.3.1 Auxiliary Feedwater System—Summary of Aging Management Evaluation—LRA Table 3.4.2-1

Carbon Steel Piping Exposed to Diesel Exhaust. In LRA Table 3.4.2-1, the applicant stated that carbon steel piping exposed to diesel exhaust (internal) will be managed for cumulative fatigue damage by a TLAA. The AMR item cites generic Note H, which states that the TLAA is evaluated in LRA Section 4.3. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3, for this component and material. The staff's evaluation of the fatigue TLAA for the AFW system is documented in SER Section 4.3.

Carbon Steel Components Exposed to Air with Borated Water Leakage. The staff's evaluation for carbon steel components exposed to air with borated water leakage, for which the applicant did not include AMR items for loss of material due to general, pitting, and crevice corrosion, is documented in SER Section 3.2.2.3.1.

Carbon Steel Heat Exchangers with Internal Coating or Lining Exposed to Raw Water. The staff's evaluation for carbon steel heat exchangers with internal coating or lining exposed to raw water, which will be managed for loss of coating integrity by the Open-Cycle Cooling Water System program and are associated with generic Note H, is documented in SER Section 3.3.2.3.22.

The staff concludes for items in LRA Table 3.4.2-1 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.2 Condensate and Feedwater Auxiliaries 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 condensate and feedwater auxiliaries system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the condensate and feedwater auxiliaries system component groups are consistent with the GALL Report.

3.4.2.3.3 Main Condensate and Feedwater System—Summary of Aging Management Evaluation—LRA Table 3.4.2-3

Aluminum Alloy Heater Wells Exposed Internally to Waste Water (Byron only). In LRA Table 3.4.2-3, the applicant stated that aluminum alloy heater wells exposed internally to waste water (Byron only) will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR item cites generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states that aluminum exposed to various water environments should be managed for loss of material, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.11. The staff noticed that this program includes opportunistic visual inspections to detect corrosion. At a minimum, the program includes inspections of a representative sample of components in each 10-year period to ensure that each material, environment, and aging effect combination is sufficiently inspected. The staff finds the applicant's proposal to manage the effects of aging using the

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections capable of detecting loss of material.

Polymeric Piping, Piping Components, and Piping Elements Exposed to Treated Water (internal) (Braidwood Unit 2 only). In LRA Table 3.4.2-3, the applicant stated that for polymeric piping, piping components, and piping elements exposed to treated water (internal) at Braidwood Unit 2 only, aging effects are not applicable and no AMP is proposed. The AMR item cites generic Note G. The AMR item cites plant-specific Note 5, which states, "[c]omponent material is HDPE (High Density Polyethylene) which corresponds to the GALL Report material of Polymers. High Density Polyethylene has no aging effects in the Treated Water environment."

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noticed that the "Complete Part Design Handbook – For Injection Molding of Thermoplastics," Alfredo E. Campo, Hanser Publishers, 2006, Chapter 9.4, "Chemical and Environmental Resistance," states:

> Considerable general information on the resistance of thermoplastics to environmental attack can be obtained from studying their structure. Aliphatic hydrocarbon polymers, such as HDPE and n-octane, will be resistant to attack by water, aqueous salt solutions, aqueous alkaline solutions, polar solvents such as ethanol, and nonoxidizing acids such as hydrochloric acid.

The staff finds the applicant's proposal acceptable based on its review of the above reference because HDPE is resistant to attack by treated water.

Stainless Steel Bolting Exposed to Soil (Braidwood Unit 2 only). In LRA Table 3.4.2-3, the applicant stated that SS bolting exposed to soil will be managed for cracking by the Buried and Underground Piping program. The AMR item cites generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that SS bolting exposed to soil is susceptible to loss of preload and loss of material due to pitting and crevice corrosion and recommends GALL Report AMPs XI.M18, "Bolting Integrity," and XI.M41, "Buried and Underground Piping and Tanks," to manage the aging effects. However the applicant has identified cracking as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in other AMR items in LRA Table 3.4.2-3.

The staff's evaluation of the applicant's Buried and Underground Piping program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage cracking using the Buried and Underground Piping program acceptable because the program includes periodic visual examinations that are capable of detecting cracking in SS bolting.

Stainless Steel Piping, Piping Components and Piping Elements Exposed to Soil (Braidwood Unit 2 only). In LRA Table 3.4.2-3, the applicant stated that SS piping, piping components, and piping elements exposed to soil will be managed for cracking by the Buried and Underground Piping Program. The AMR item cites generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that SS piping, piping components, and piping elements exposed to soil is susceptible to loss of material due to pitting and crevice corrosion and recommends GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks,” to manage the aging effects. However the applicant has identified cracking as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.4.2-3.

The staff’s evaluation of the applicant’s Buried and Underground Piping program is documented in SER Section 3.0.3.2.15. The staff finds the applicant’s proposal to manage cracking using the Buried and Underground Piping program acceptable because the program includes periodic visual examinations that are capable of detecting cracking in SS piping, piping components, and piping elements.

The staff concludes for items in LRA Table 3.4.2-3 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.4 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 AMR evaluations for the main steam system component groups. The staff‘s review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the main steam system component groups are consistent with the GALL Report.

3.4.2.3.5 Main Turbine and Auxiliaries System—Summary of Aging Management Evaluation—LRA Table 3.4.2-5

Carbon Steel Flow Devices Exposed to Treated Water. In LRA Table 3.4.2-5, the applicant stated that carbon steel flow devices exposed to treated water will be managed for loss of material due to mechanisms other than flow-accelerated corrosion by the Flow-Accelerated Corrosion Program. The AMR item cites generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, and the applicant addressed the aging effects identified in the GALL Report for this component, material, and environment combination using other items in LRA Table 3.4.2-5. However, the applicant has identified wall thinning due to mechanisms other than flow-accelerated corrosion as an additional aging effect.

The staff’s evaluation of the applicant’s Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.1.5. The staff noticed that the applicant revised this AMR item in its response dated May 15, 2014, to RAI B.2.1.8-1, regarding the currently implemented Flow-Accelerated Corrosion program at Byron and Braidwood. The staff also notes that the applicant’s use of the Flow-Accelerated Corrosion program to manage non–flow-accelerated corrosion aging mechanisms is consistent with LR-ISG-2012-01, “Wall Thinning Due to Erosion Mechanisms.” The staff finds the applicant’s proposal to manage wall thinning due to mechanisms other than flow-accelerated corrosion using the Flow-Accelerated Corrosion Program acceptable because the program determines ongoing wear rates and either schedules the next inspections before the component reaches minimum wall thickness or takes corrective actions to repair or replace the component.

The staff concludes for items in LRA Table 3.4.2-5 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 groups of the following SCs:

- auxiliary building
- circulating water pump house (Byron)
- component supports commodity group
- containment structure
- deep well enclosures (Byron)
- essential service cooling pond (Braidwood)
- essential service water cooling towers (Byron)
- fuel handling building
- lake screen structures (Braidwood)
- main steam & AFW tunnels and isolation valve rooms
- natural draft cooling towers (Byron)
- RWST foundation and tunnel
- radwaste and service building complex
- river screen house (Byron)
- structural commodity group
- switchyard structures
- turbine building complex
- yard structures

The GALL Report organizes safety-related and other structures (other than containments), such as those listed above, into nine groups. These nine groups, which are referenced in the LRA and staff's evaluation as Groups 1 - 9 Structures, are generically defined in GALL Report Chapter III.A.

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 the 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 OE 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 OE included a review of the GALL Report and OE issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

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 Containment, Structures, and Component Supports Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all (3.5.1-1)	Cracking and distortion due to increased stress levels from settlement	Chapter XI.S2, "ASME Section XI, Subsection IWL" or Chapter XI.S6, "Structure Monitoring" If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Structures Monitoring program and ASME Section XI, Subsection IWL program	Consistent with the GALL Report (see SER Section 3.5.2.2.1)
Concrete: foundation; subfoundation (3.5.1-2)	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring" If a de-watering system is relied upon for control of erosion, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.5.2.2.1)
Concrete: dome; wall; basemat; ring girders; buttresses; concrete: containment; wall; basemat; concrete: basemat, concrete fill-in annulus (3.5.1-3)	Reduction of strength and modulus due to elevated temperature (>150 °F general; >200 °F local)	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.5.2.2.1)
Steel elements (inaccessible areas): drywell shell, drywell head, and drywell shell (3.5.1-4)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements (inaccessible areas): liner; liner anchors; integral attachments; Steel elements (inaccessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable) (3.5.1-5)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE" and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes	ASME Section XI, Subsection IWE program and 10 CFR Part 50, Appendix J program	Consistent with the GALL Report (see SER Section 3.5.2.2.1)
Steel elements: torus shell (3.5.1-6)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE" and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1)
Steel elements: torus ring girders; downcomers; steel elements: suppression chamber shell (interior surface) (3.5.1-7)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE"	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1)
Prestressing system: tendons (3.5.1-8)	Loss of prestress due to relaxation; shrinkage; creep; elevated temperature	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Penetration sleeves; penetration bellows steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell; unbraced downcomers, steel elements: vent header; downcomers (3.5.1-9)	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.1)
Penetration sleeves; penetration bellows (3.5.1-10)	Cracking due to SCC	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWE program and 10 CFR Part 50, Appendix J program	Consistent with the GALL Report (see SER Section 3.5.2.2.1)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): basemat, concrete (inaccessible areas): dome; wall; basemat (3.5.1-11)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-in./yr) (NUREG-1557).	Yes	ASME Section XI, Subsection IWL program	Consistent with the GALL Report (see SER Section 3.5.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, Concrete (inaccessible areas): basemat, concrete (inaccessible areas): containment; wall; basemat, concrete (inaccessible areas): basemat, concrete fill-in annulus (3.5.1-12)	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	ASME Section XI, Subsection IWL program	Consistent with the GALL Report (see SER Section 3.5.2.2.1)
Concrete (inaccessible areas): basemat, concrete (inaccessible areas): dome; wall; basemat (3.5.1-13)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.5.2.2.1)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): containment; wall; basemat (3.5.1-14)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	ASME Section XI, Subsection IWL program and Structures Monitoring program	Consistent with the GALL Report (see SER Section 3.5.2.2.1)
Concrete (accessible areas): basemat (3.5.1-15)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (accessible areas): basemat, concrete: containment; wall; basemat (3.5.1-16)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to Byron and Braidwood
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses (3.5.1-17)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): basemat (3.5.1-18)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): basemat, concrete (accessible areas): containment; wall; basemat, concrete (accessible areas): basemat, concrete fill-in annulus (3.5.1-19)	Cracking due to expansion from reaction with aggregates	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): containment; wall; basemat (3.5.1-20)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel, concrete (accessible areas): basemat; reinforcing steel, concrete (accessible areas): dome; wall; basemat; reinforcing steel (3.5.1-21)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Concrete (inaccessible areas): basemat; reinforcing steel (3.5.1-22)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to PWRs
Concrete (inaccessible areas): basemat; reinforcing steel, concrete (inaccessible areas): dome; wall; basemat; reinforcing steel (3.5.1-23)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to Byron and Braidwood
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): basemat, concrete (accessible areas): dome; wall; basemat (3.5.1-24)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program and ASME Section XI, Subsection IWL program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel (3.5.1-25)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Moisture barriers (caulking, flashing, and other sealants) (3.5.1-26)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell (3.5.1-27)	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to Byron and Braidwood
Personnel airlock, equipment hatch, CRD hatch (3.5.1-28)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWL program and 10 CFR Part 30 Appendix J program	Consistent with the GALL Report
Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms (3.5.1-29)	Loss of leak tightness due to mechanical wear of locks, hinges and closure mechanisms	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWL program and 10 CFR Part 30 Appendix J program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Pressure-retaining bolting (3.5.1-30)	Loss of preload due to self-loosening	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWL program and 10 CFR Part 30 Appendix J program	Consistent with the GALL Report
Pressure-retaining bolting, steel elements: downcomer pipes (3.5.1-31)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	ASME Section XI, Subsection IWE program	Consistent with the GALL Report
Prestressing system: tendons; anchorage components (3.5.1-32)	Loss of material due to corrosion	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Seals and gaskets (3.5.1-33)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	10 CFR Part 50, Appendix J program	Consistent with the GALL Report
Service Level I coatings (3.5.1-34)	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	Protective Coating Monitoring and Maintenance program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, steel elements (accessible areas): drywell shell; drywell head; drywell shell in sand pocket regions; steel elements (accessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable), steel elements (accessible areas): drywell shell; drywell head (3.5.1-35)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	ASME Section XI, Subsection IWE program and 10 CFR Part 50, Appendix J program	Consistent with the GALL Report
Steel elements: drywell head; downcomers (3.5.1-36)	Fretting or lockup due to mechanical wear	Chapter XI.S1, “ASME Section XI, Subsection IWE”	No	Not applicable	Not applicable to PWRs
Steel elements: suppression chamber (torus) liner (interior surface) (3.5.1-37)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Not applicable	Not applicable to PWRs
Steel elements: suppression chamber shell (interior surface) (3.5.1-38)	Cracking due to SCC	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Not applicable	Not applicable to PWRs
Steel elements: vent line bellows (3.5.1-39)	Cracking due to SCC	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	Not applicable	Not applicable to PWRs

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Unbraced downcomers, Steel elements: vent header; downcomers (3.5.1-40)	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	Not applicable	Not applicable to PWRs
Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt (3.5.1-41)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to PWRs
Groups 1-3, 5, 7-9: concrete (inaccessible areas): foundation (3.5.1-42)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index >100 day-in./yr) (NUREG-1557)	Yes	Structures Monitoring program	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1(1))
All Groups except Group 6: concrete (inaccessible areas): all (3.5.1-43)	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Structures Monitoring program	Consistent with the GALL Report (see SER Section 3.5.2.2.2)
All Groups: concrete: all (3.5.1-44)	Cracking and distortion due to increased stress levels from settlement	Chapter XI.S6, "Structures Monitoring." If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Structures Monitoring program	Consistent with the GALL Report (see SER Section 3.5.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-45)	Reduction in foundation strength, cracking due to differential settlement, erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring." If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.2)
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-46)	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring." If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.5.2.2.2)
Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation (3.5.1-47)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes,	Structures Monitoring program	Consistent with the GALL Report (see SER Section 3.5.2.2.2)
Groups 1-5: concrete: all (3.5.1-48)	Reduction of strength and modulus due to elevated temperature (>150 °F general; >200 °F local)	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.5.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-49)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index >100 day-in./yr) (NUREG-1557)	Yes	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report (see SER Section 3.5.2.2.2)
Groups 6: concrete (inaccessible areas): all (3.5.1-50)	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report (see SER Section 3.5.2.2.2)
Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-51)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific AMP is needed.	Yes	Structures Monitoring program and RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report (see SER Section 3.5.2.2.2)
Groups 7, 8 - steel components: tank liner (3.5.1-52)	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 Byron and Braidwood (see SER Section 3.5.2.2.2)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-53)	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.2)
All groups except 6: concrete (accessible areas): all (3.5.1-54)	Cracking due to expansion from reaction with aggregates	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring Program and RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-55)	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Concrete: exterior above- and below-grade; foundation; interior slab (3.5.1-56)	Loss of material due to abrasion; cavitation	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program and Structures Monitoring program	Consistent with the GALL Report
Constant and variable load spring hangers; guides; stops (3.5.1-57)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program	Consistent with the GALL Report
Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds (3.5.1-58)	Loss of material; loss of form due to erosion, settlement, sedimen-tation, frost action, waves, currents, surface runoff, seepage	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: concrete (accessible areas): all (3.5.1-59)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report
Group 6: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-60)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report
Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-61)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: wooden piles; sheeting (3.5.1-62)	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	Not applicable	Not applicable to Byron and Braidwood
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-63)	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-64)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all (3.5.1-65)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior (3.5.1-66)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program and Fire Protection System program	Consistent with the GALL Report
Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1–3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all (3.5.1-67)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
High-strength structural bolting (3.5.1-68)	Cracking due to SCC	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program Exceptions apply to ASME Section XI, Subsection IWF program	Consistent with the GALL Report
High-strength structural bolting (3.5.1-69)	Cracking due to SCC	Chapter XI.S6, "Structures Monitoring" Note: ASTM A 325, F 1852, and ASTM A 490 bolts used in civil structures have not shown to be prone to SCC. SCC potential need not be evaluated for these bolts.	No	Not applicable	Not applicable to Byron and Braidwood
Masonry walls: all (3.5.1-70)	Cracking due to restraint shrinkage, creep, and aggressive environment	Chapter XI.S5, "Masonry Walls"	No	Masonry Walls program and Fire Protection System program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Masonry walls: all (3.5.1-71)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Chapter XI.S5, "Masonry Walls"	No	Masonry Walls program	Consistent with the GALL Report
Seals; gasket; moisture barriers (caulking, flashing, and other sealants) (3.5.1-72)	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program and ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Service Level I coatings (3.5.1-73)	Loss of coating integrity due to blistering, cracking, flaking, peeling, physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	Protective Coating Monitoring and Maintenance program	Consistent with the GALL Report
Sliding support bearings; sliding support surfaces (3.5.1-74)	Loss of mechanical function due to corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Sliding surfaces (3.5.1-75)	Loss of mechanical function due to corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program Exceptions apply to ASME Section XI, Subsection IWF program	Consistent with the GALL Report
Sliding surfaces: radial beam seats in BWR drywell (3.5.1-76)	Loss of mechanical function due to corrosion, distortion, dirt, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel components: all structural steel (3.5.1-77)	Loss of material due to corrosion	Chapter XI.S6, "Structures Monitoring." If protective coatings are relied upon to manage the effects of aging, the structures monitoring program is to include provisions to address protective coating monitoring and maintenance.	No	Structures Monitoring program	Consistent with the GALL Report
Steel components: fuel pool liner (3.5.1-78)	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Monitoring of the spent fuel pool water level in accordance with TSs and leakage from the leak chase channels	No, unless leakages have been detected through the SFP liner that cannot be accounted for from the leak chase channels	Water Chemistry Program and Structures Monitoring Program	Consistent with the GALL Report
Steel components: piles (3.5.1-79)	Loss of material due to corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Structural bolting (3.5.1-80)	Loss of material due to general, pitting and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, and ASME Section XI, Subsection IWL program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural bolting (3.5.1-81)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program Exceptions apply to ASME Section XI, Subsection IWF program	Consistent with the GALL Report
Structural bolting (3.5.1-82)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, and ASME Section XI, Subsection IWL program	Consistent with the GALL Report
Structural bolting (3.5.1-83)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program	Consistent with the GALL Report
Structural bolting (3.5.1-84)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Water Chemistry Program and ASME Section XI, Subsection IWF Program Exceptions apply to ASME Section XI, Subsection IWF Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural bolting (3.5.1-85)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water, and Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Water Chemistry Program and ASME Section XI, Subsection IWF Program Exceptions apply to ASME Section XI, Subsection IWF Program	Consistent with the GALL Report
Structural bolting (3.5.1-86)	Loss of material due to pitting and crevice corrosion	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program Exceptions apply to ASME Section XI, Subsection IWF program	Consistent with the GALL Report
Structural bolting (3.5.1-87)	Loss of preload due to self-loosening	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program Exceptions apply to ASME Section XI, Subsection IWF program	Consistent with the GALL Report
Structural bolting (3.5.1-88)	Loss of preload due to self-loosening	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, and ASME Section XI, Subsection IWL program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-89)	Loss of material due to boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-90)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water, and Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to Byron and Braidwood
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-91)	Loss of material due to general and pitting corrosion	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF program	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-92)	Loss of material due to general and pitting corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-93)	Loss of material due to pitting and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring program	Consistent with the GALL Report
Vibration isolation elements (3.5.1-94)	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Structures Monitoring program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum, galvanized steel and stainless steel support members; welds; bolted connections; support anchorage to building structure exposed to air – indoor, uncontrolled (3.5.1-95)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	Consistent with the GALL Report

The staff's review of the containments, structures, and component supports components 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 containments, structures, and component supports component groups is documented in SER Section 3.0.3.

3.5.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the containments, 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
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Masonry Walls
- One-Time Inspection
- Open-Cycle Cooling Water System
- Protective Coating Monitoring and Maintenance Program
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Selective Leaching
- Structures Monitoring
- TLAA
- Water Chemistry

Although not identified directly in LRA Section 3.5.2.1, LRA Table 3.5.1 identifies the TLAA Program under the discussion column that manages aging effects for the structures and structural components and their commodity groups for specified conditions.

LRA Tables 3.5.2-1 through 3.5.2-12 summarize AMRs for the containments, structures, and component supports component 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 GALL Report and for which the GALL Report 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 in the LRA for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A–E, indicating how the AMR is consistent with the GALL Report.

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

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

Note C indicates that the component for the AMR item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. Note C 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 items to confirm consistency with the GALL Report. The staff also determined whether the AMR item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

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

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect but credits a different AMP. The staff reviewed these items to confirm 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.

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 confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

3.5.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.5.1, items 3.5.1-22 and 3.5.1-36 through 3.5.1-41, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. The staff reviewed the SRP-LR, confirmed these items only apply to BWRs, and the staff finds that these items are not applicable to Byron and Braidwood, which are PWRs.

For LRA Table 3.5.1, items 3.5.1-2, 3.5.1-15, 3.5.1-16, 3.5.1-23, 3.5.1-27, and 3.5.1-62, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Byron and Braidwood. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.5.1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff nonapplicability verification of these items required the review of sources beyond the LRA and UFSAR, and/or the issuance of RAIs.

LRA Table 3.5.1, item 3.5.1-69 addresses LAS high-strength structural bolting exposed to air-indoor, uncontrolled or air-outdoor. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to manage cracking due to SCC for this component group. The applicant stated that this item is not applicable because high-strength structural bolts used at BBS (ASTM A 325 and A 490) have not been shown to be susceptible to SCC. The staff evaluated the applicant's claim and finds it acceptable because the GALL Report states that the potential of SCC need not to be evaluated for ASTM A 325 and A 490 high-strength structural bolts exposed to air-indoor, uncontrolled or air-outdoor.

LRA Table 3.5.1, item 3.5.1-90 addresses steel and SS support members; welds; bolted connections; support anchorage to building structure exposed to treated water. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry" and XI.S3, "ASME Section XI, Subsection IWF" to manage loss of material due to general (steel only), pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because there are no support members, welds, bolted connections, or support anchorage to building structure for Class 1 piping and component supports exposed to treated water at Byron and Braidwood. The applicant stated that Class 1 piping and component supports are only located inside the containment structures and are not exposed to a treated borated water environment at Byron and Braidwood. The applicant also stated that Class 2 and 3 piping and component supports exposed to treated borated water have been aligned to Item Number 3.5.1-85, and that Class MC supports exposed to treated borated water have been aligned to Item Number 3.5.1-84. The staff noticed that in LRA Table 3.0-1, Byron and Braidwood Service Environments, the applicant included GALL Report environment "treated water" in its comparison to the "treated borated water" environment at BBS. Additionally, the

LRA states that this environmental alignment is only utilized for certain structural items, such as those that are exposed to treated borated water, and that the differences between environments do not affect the aging management of the loss of material for these components.

The staff evaluated the applicant's claim that the component and environment combination of Class 1 piping and component supports exposed to treated water is not applicable. The staff noticed that GALL Report line item III.B1.1.TP-10 applies to steel and SS support members, welds, bolted connections and support anchorage that are submerged in water. The applicant stated that the only Class 1 piping and component supports are in Containment. The staff reviewed LRA Section 2 and noticed that the only treated borated water inside Containment exists inside of the pipes, and that the only exposure to borated water would be from leakage. The staff also noticed that Class 1 piping and component supports are managed for an environment of "air with borated water leakage," which is the environment to which the components would be exposed in Containment, by the ASME Section XI, Subsection IWF program. Additionally, the staff noticed that borated water leakage is managed by the Boric Acid Corrosion Program. The staff finds the applicant's claim that this item is not applicable for Class 1 piping and component supports acceptable because (1) there are no Class 1 piping and component supports exposed to a treated borated water environment; and (2) Class 1 piping and component supports in Containment are being managed for this aging effect through the ASME Section XI, Subsection IWF program.

For Class 2 and Class 3 piping and component supports exposed to treated borated water, the staff evaluated the applicant's realignment of this component and environment to item 3.5.1-85. This item corresponds to GALL Report item III.B1.2.TP-232, which applies to SS structural bolting exposed to treated water and subject to loss of material due to pitting and crevice corrosion for Class 2 and 3 component supports. The Discussion column of LRA Table 3.5.1, item 3.5.1-85, states that the ASME Section XI, Subsection IWF program and the Water Chemistry Program will be used to manage loss of material of SS structural bolting and supports for ASME Class 2 and 3 piping and components exposed to treated borated water. The staff finds this acceptable because the applicant will manage aging with the ASME Section XI, Subsection IWF program and the Water Chemistry Program, consistent with GALL Report Recommendations.

For Class MC Supports exposed to treated borated water, the staff evaluated the applicant's realignment of this component and environment to item number 3.5.1-84. This item corresponds to GALL Report item III.B1.3.TP-232, which applies to SS structural bolting exposed to treated water and subject to loss of material due to pitting and crevice corrosion for Class MC supports. The Discussion column of LRA Table 3.5.1, item 3.5.1-84, states that the Water Chemistry program and ASME Section XI, Subsection IWF program will be used to manage loss of material of SS structural bolting and supports for ASME Class MC supports exposed to treated borated water. The staff finds this acceptable because the applicant will manage aging with the ASME Section XI, Subsection IWF program and the Water Chemistry Program, consistent with the GALL Report Recommendations.

3.5.2.1.2 Cracking Due to Expansion from Reaction with Aggregates

LRA Table 3.5.1, item 3.5.1-54, as revised by letter dated June 9, 2014, in response to RAI 3.5.2.2.1-1, addresses accessible areas of concrete for all groups of structures, except 6, exposed to any environment, which will be managed for cracking due to expansion from reaction with aggregates. For the AMR items that cite generic Note E, the LRA credits the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program to manage the aging effect for accessible areas of concrete in group 6 structures. The staff notes that the GALL Report does not contain a line item for accessible areas of group 6 structures; therefore, the applicant's comparison of this structure to the structures listed in SRP-LR item 3.5.1-54 and proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as opposed to the Structures Monitoring Program, is appropriate. The Structures Monitoring Program recommends periodic visual inspections, by qualified personnel, at an interval not to exceed five years.

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 3.0.3.2.21. The staff's evaluation of the applicant's response to RAI 3.5.2.2.1-1 is documented in SER Section 3.5.2.2.1. The staff noticed that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program proposes to manage the effects of aging for concrete structures through periodic visual inspections by qualified personnel, at an interval not to exceed five years. The staff also notes that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced to perform inspections of the essential service water cooling towers at Byron, on a three-year interval as a result of OE related to the effects of freeze-thaw. Based on its review of components associated with items 3.5.1-54 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because the periodic visual inspections performed under this program are capable to detecting this aging effect and are consistent, in terms of inspection guidance and frequency, with the recommendations for visual inspections in the Structures Monitoring Program.

The staff concludes that for LRA Item 3.5.1-54, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.3 Loss of Material Due to Abrasion; Cavitation

LRA Table 3.5.1, item 3.5.1-56 addresses concrete: exterior above- and below- grade; foundation; and interior slab exposed to water-flowing, which will be managed for loss of material due to abrasion or cavitation. For the AMR items that cite generic Note E, the LRA credits the Structures Monitoring Program to manage the aging effect for inaccessible, exterior, above- and below-grade reinforced concrete for the Natural Draft Cooling Towers at Byron. The GALL Report recommends GALL Report AMP XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants to ensure that this aging effect is adequately managed. GALL Report AMP XI.S7 recommends using periodic visual inspections, performed by qualified engineers, on a frequency of at least once every 5 years to manage the effects of aging. GALL Report AMP XI.S7 also recommends that for plants with an aggressive environment (pH < 5.5, chlorides > 500 ppm, or sulfates > 1500 ppm) and/or where the concrete structural elements have experienced degradation, a plant-specific AMP accounting for the extent of the degradation experienced should be implemented to manage the effects of aging on concrete during the period of extended operation.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff noticed that the Structures Monitoring Program proposes to manage the effects of aging for inaccessible, exterior, above- and below-grade reinforced concrete for the Natural Draft Cooling Towers at Byron by using periodic visual inspections performed by personnel meeting the qualifications specified in ACI 349.3R. Based on its review of components associated with item 3.5.1-56 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because the Structures Monitoring Program will be enhanced to:

(1) monitor groundwater chemistry on a frequency not to exceed 5 years for pH, chlorides, and sulfates and evaluate results exceeding the threshold criteria to assess the impact, if any, on below-grade concrete

(2) At a 5-year frequency, inspect a structure that will be used as a leading indicator for the condition of below-grade concrete exposed to groundwater

(3) require (a) the evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, and (b) examination of representative samples of the exposed portions of the below-grade concrete when exposed for any reason, and

(4) require visual inspection of submerged concrete structural elements by dewatering a structure or by a diver if the structure is not dewatered at least once every 5 years (Byron only).

The staff concludes that for LRA item 3.5.1-56, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.4 Cracking Due to Restraint Shrinkage, Creep, and Aggressive Environment

LRA Table 3.5.1, item 3.5.1-70 addresses all masonry walls exposed to air-indoor uncontrolled (external), air-outdoor (external), or air with borated water leakage, which will be managed for cracking due to restraint shrinkage, creep, and aggressive environment. For the AMR items that cite generic Note E, the LRA credits the Fire Protection Program to manage the aging effect for concrete block fire barriers (masonry walls). The GALL Report recommends GALL Report AMP XI.S5, Masonry Walls to ensure that this aging effect is adequately managed. However, GALL Report AMP XI.S5 states that the aging effects on masonry walls that are considered fire barriers are also managed by GALL Report AMP XI.M26, Fire Protection. The staff notes that the applicant has appropriately assessed cracking due to restraint shrinkage, creep, and aggressive environment, for the masonry walls that are also considered fire barriers.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.10. The staff noticed that the Fire Protection Program proposes to manage the effects of aging for concrete block fire barriers (masonry walls) through the use of visual inspections by personnel qualified and trained to perform the inspection activities, at a frequency consistent with their NRC-approved fire protection program. Based on its review of components associated with item 3.5.1-70 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage the effects of aging using the Fire Protection Program acceptable because (1) the applicant's program is consistent, with enhancements, with GALL Report AMP XI.M26 which recommends periodic visual inspections of fire barrier walls, ceilings, and floors, and (2) the applicant's program will be enhanced to provide additional inspection guidance to identify age-related degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material.

The staff concludes that for LRA item 3.5.1-70, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.5 Loss of Sealing Due to Deterioration of Seals, Gaskets, and Moisture Barriers (Caulking, Flashing, and Other Sealants)

LRA Table 3.5.1, item 3.5.1-72 addresses elastomeric seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) exposed to air-indoor uncontrolled and air outdoor, which will be managed for loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants). For the AMR items that cite generic Note E, the LRA credits the ASME Section XI, Subsection IWL Program to manage the aging effect for elastomeric gaskets for grease caps at tendon anchorages. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends using periodic visual inspections by a qualified inspector to manage the effects of aging.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The ASME Section XI, Subsection IWL Program implements examination requirements of the ASME B&PV Code, Section XI, Subsection IWL as required by 10 CFR 50.55a. The staff noticed that the ASME Section XI Subsection IWL Program proposes to manage the effects of aging for prestressing systems through the use of periodic visual examinations consistent with Sections IWL-2400 and 2500 of the ASME Code. Section IWL-2524.1 requires that a detailed visual examination of the tendon anchorage hardware be performed to determine the condition (e.g., cracks, wear, or corrosion) of anchorage hardware. Loss of sealing of the elastomeric gaskets for grease caps at tendon anchorages may result in leakage of water and/or corrosion protection medium (i.e., grease). The staff notes that Sections IWL-3221.3 and 3221.4 of the ASME Code state that the acceptance criteria for tendon anchorage areas and grease is met when there is no evidence of free water and the amount of grease replaced does not exceed 10 percent of the tendon net duct volume. The ASME Code requires that items that do not meet the acceptance criteria be evaluated consistent with IWL-3300 which requires the preparation of an Engineering Evaluation Report. Based on its review of components associated with item 3.5.1-72 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the ASME Section XI Subsection IWL Program acceptable because (1) the proposed AMP requires that periodic detailed visual examination of the anchorage hardware be performed to determine the condition of this component consistent with the ASME Code, and (2) the detailed visual inspection should be able to detect loss of sealing of the elastomeric gaskets for grease caps at tendon anchorages.

The staff concludes that for LRA item 3.5.1-72 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

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

LRA Table 3.5.1, item 3.5.1-80 addresses steel structural bolting exposed to air-indoor uncontrolled, which will be managed for loss of material due to general pitting and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the ASME Section XI, Subsection IWL Program to manage the aging effect for carbon and LAS bolting at tendon anchorage grease caps. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends using periodic visual inspections to manage the effects of aging.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The ASME Section XI, Subsection IWL Program implements examination requirements of the ASME B&PV Code, Section XI, Subsection IWL as required by 10 CFR 50.55a. The staff noticed that the ASME Section XI Subsection IWL Program proposes to manage the effects of aging for prestressing systems through the use of periodic visual examinations consistent with Sections IWL-2400 and 2500 of the ASME Code. Section IWL-2524.1 requires that a detailed visual examination of the tendon anchorage hardware be performed to determine the condition (e.g., cracks, wear, or corrosion) of anchorage hardware. Based on its review of components associated with item 3.5.1-80 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWL Program acceptable because the required detailed visual examination of the tendon anchorage area will detect a loss of material of the tendon grease cap bolts.

LRA Table 3.5.1, item 3.5.1-82 addresses steel structural bolting exposed to air-outdoor, which will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the ASME Section XI, Subsection IWL Program to manage the aging effect for carbon and LAS bolting at tendon anchorage grease caps. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends using periodic visual inspections to manage the effects of aging.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The ASME Section XI, Subsection IWL Program implements examination requirements of the ASME B&PV Code, Section XI, Subsection IWL as required by 10 CFR 50.55a. The staff noticed that the ASME Section XI Subsection IWL Program proposes to manage the effects of aging for prestressing systems through the use of periodic visual examinations consistent with Sections IWL-2400 and 2500 of the ASME Code. Section IWL-2524.1 requires that a detailed visual examination of the tendon anchorage hardware be performed to determine the condition (e.g., cracks, wear, or corrosion) of anchorage hardware. Based on its review of components associated with item 3.5.1-82 for which the applicant cited generic Note E, the staff finds the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWL Program acceptable because the required detailed visual examination of the tendon anchorage area will detect a loss of material of the tendon anchorage bolts.

The staff concludes that for LRA items 3.5.1-80 and 82 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.7 Loss of Preload Due to Self-Loosening

LRA Table 3.5.1, item 3.5.1-88 addresses steel structural bolting exposed to air-indoor uncontrolled or air-outdoor, which will be managed for loss of preload due to self-loosening. For the AMR items that cite generic note E, the LRA credits the ASME Section XI, Subsection IWL Program to manage the aging effect for carbon and LAS structural bolting at tendon anchorage grease caps. The GALL Report recommends GALL Report AMP XI.S6, “Structures Monitoring,” to ensure that this aging effect is adequately managed. GALL Report AMP XI.S6 recommends periodic visual inspections of structural bolting to manage the effects of aging.

The staff’s evaluation of the applicant’s ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The ASME Section XI, Subsection IWL Program implements examination requirements of the ASME B&PV Code, Section XI, Subsection IWL as required by 10 CFR 50.55a. The staff noticed that the ASME Section XI Subsection IWL Program proposes to manage the effects of aging for prestressing systems through the use of periodic visual examinations consistent with Sections IWL-2400 and 2500 of the ASME Code. Section IWL-2524.1 requires that a detailed visual examination of the tendon anchorage hardware be performed to determine its condition. Based on its review of components associated with item 3.5.1-88 for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage the effects of aging using the ASME Section XI, Subsection IWL Program acceptable because the required detailed visual examination of the tendon anchorage area will detect loose bolts, missing or loose nuts, and other conditions indicative of loss of preload in the tendon grease cap bolts.

The staff concludes that for LRA item 3.5.1-88 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.8 Reduction or Loss of Isolation Function Due to Radiation Hardening, Temperature, Humidity, Sustained Vibratory Loading

LRA Table 3.5.1, item 3.5.1-94 addresses elastomeric vibration isolation elements exposed to air – indoor, uncontrolled or air – outdoor environment, which will be managed for reduction or loss of isolation function due to radiation hardening, temperature, humidity, or sustained vibratory loading. For the AMR item that cites generic Note E, the LRA credits the Structures Monitoring Program to manage the aging effect for elastomeric supports for EDG, HVAC system components, and other miscellaneous mechanical equipment (vibration isolation elements). The GALL Report recommends GALL Report AMP XI.S3 ASME Section XI, Subsection IWF to ensure that this aging effect is adequately managed. The LRA states that the Structures Monitoring program has been substituted and will be used to manage the reduction or loss of isolation function of elastomeric vibration isolation elements associated with non-ASME supports, primarily HVAC equipment, exposed to an indoor air environment. The LRA continues that Byron and Braidwood do not have vibration element components in Classes 1, 2, or 3 nonexempt supports. GALL Report AMP XI.S3 recommends using VT-3 visual inspections to manage the effects of aging for ASME Code Classes 1, 2, 3 and MC piping and components and their associated supports under the ASME Section XI, Subsection IWF AMP. The Structures Monitoring program includes all component supports in the scope of license renewal that are not covered by the ASME Section XI, Subsection IWF program.

The staff's evaluation of the applicant's Structures Monitoring program is documented in SER Section 3.0.3.2.20. The staff noticed that the Structures Monitoring program proposes to manage the effects of aging for elastomers (including vibration isolation elements) through the use of periodic visual inspections. The Structures Monitoring program will monitor these components for hardening, shrinkage, and a loss of sealing in air – outdoor and air – indoor, uncontrolled environments. The presence of these aging mechanisms detected through periodic visual inspection will be leading indicators of a reduction or loss of isolation function and implement corrective actions prior to a loss of intended function. Based on its review of components associated with item 3.5.1-94 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring program acceptable because (1) the elastomeric vibration isolation elements present at Byron and Braidwood are not supporting the function of any component supports required to be inspected by ASME Section XI, Subsection IWF per 10 CFR 50.55a; and (2) the Structures Monitoring program will use periodic visual examination by a qualified inspector to ensure that for the elastomeric vibration isolation elements in the scope of license renewal, aging mechanisms will be detected before there is a loss of license renewal intended function.

The staff concludes that for LRA item 3.5.1-94 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.5.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the containments, structures, and component supports components and provides information concerning how it will manage the following aging effects:

(1) PWR and BWR containments:

- cracking and distortion due to increased stress levels from settlement; reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundations
- reduction of strength and modulus due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to SCC
- cracking due to cyclic loading
- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregates
- increase in porosity and permeability due to leaching of calcium hydroxide and carbonation

(2) safety-related and other structures and component supports:
   - aging management of inaccessible areas
   - reduction of strength and modulus due to elevated temperature
   - aging management of inaccessible areas for Group 6 structures
   - cracking due to SCC and loss of material due to pitting and crevice corrosion
   - cumulative fatigue damage due to fatigue

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. The staff's review of the applicant's further evaluation follows.

3.5.2.2.1 PWR and BWR Containments

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which address several areas:

<u>Cracking and Distortion Due to Increased Stress Levels from Settlement, Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations</u>. LRA Section 3.5.2.2.1, associated with LRA Table 3.5.1 item 3.5.1-1, addresses concrete containment dome, wall, basemat and buttresses exposed to soil and water – flowing which will be managed for cracking and distortion due to increased stress levels from settlement by the Structures Monitoring program. LRA Section 3.5.2.2.1 is also associated with LRA Table 3.5.1 item 3.5.1-2, which addresses concrete foundation and subfoundation subject to reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation. The criteria in SRP-LR Section 3.5.2.2.1.1 states that cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Section XI, Subsection IWL to manage these aging effects. The SRP-LR also states that reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containment. The existing program relies on the Structures Monitoring Program to manage these aging effects. However, some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system to control settlement, the GALL Report recommends further evaluation to verify the continued functionality of the de-watering system during the period of extended operation.

The applicant addressed the further evaluation criteria of the SRP-LR for item number 3.5.1-1, for the aging effect of cracking and distortion due to increased stress levels from settlement by stating that the foundations of the containment structures at BBS are supported on the underlying bedrock, as described in UFSAR Section 2.5.4.20.2.3 for Byron and UFSAR Section 2.5.4.10.1.1 for Braidwood. The LRA also states that a settlement monitoring program was implemented during construction and shortly after to monitor for settlement of Category I structure foundations at Braidwood. For Braidwood, the predicted and measured values for settlement of containment structures showed that plant settlement is complete and less than the values considered in the design of the structures. For Byron, results of calculations for settlement of the containment structures showed negligible total and differential settlement. Therefore, cracking and distortion due to increased stress levels is not expected to occur, however inaccessible below-grade containment concrete surfaces will be examined by the Structures Monitoring Program when excavated for any reason.

In its review of structures associated with item 3.5.1-1, the staff noticed the following and identified a need for additional information:

- The program description section of GALL Report AMP XI.S2, ASME Section XI, Subsection IWL states that 10 CFR 50.55a imposes the examination requirements of ASME Code, Section XI, Subsection IWL, for Class CC reinforced and Prestressed concrete containments. Section 50.55a of 10 CFR also specifies that licensees evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation of inaccessible areas.
- Although actual settlement can occur for concrete containment in a soil environment, the symptoms of that can be manifested in above-ground areas such as "air – indoor, uncontrolled," or "air – outdoor" environments and identified during visual inspections of containment per the ASME Section XI, Subsection IWL ISIs of containment.
- SRP-LR Section 3.5.2.2.1.1 states that for the aging effect/mechanism of cracking and distortion due to increased stress levels from settlement, the existing program relies on ASME Section XI, Subsection IWL to manage these aging effects.
- LRA Table 3.5.1-1 does not identify the ASME Section XI, Subsection IWL AMP, and it does not identify a technical basis justifying why the IWL program would not be used to manage this aging effect.

Therefore, by letter dated May 19, 2014, the staff requested that the applicant provide a technical basis to justify why the ASME Section XI, Subsection IWL program is not listed for aging management of concrete containment pressure-resisting boundary components in accessible and inaccessible areas. In its letter dated June 9, 2014, the applicant clarified that the ASME Section XI, Subsection IWL program will be used for aging management of accessible and inaccessible concrete containment pressure-resisting boundary component areas. The applicant revised LRA Section 3.5.2.2.1.1 and Table 3.5-1, item 3.5.1-1, to show that both the ASME Section XI, Subsection IWL program and the Structures Monitoring program will be used for aging management.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL and Structures Monitoring programs are documented in SER Sections 3.0.3.2.17 and 3.0.3.2.20, respectively. The GALL Report recommends that these programs be used to manage aging of accessible and inaccessible areas of the containment concrete. The applicant's proposal to use the ASME Section, Subsection IWL program to manage cracking and distortion due to increased stress levels from settlement is consistent with GALL Report item II.A1.CP-101 and is therefore acceptable. The staff finds that the applicant has met the further evaluation criteria and that the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWL and Structures Monitoring programs is acceptable because the ASME Section XI, Subsection IWL and Structures Monitoring programs will effectively manage cracking and distortion due to settlement of the containment concrete. Further, the foundations of the primary containment at both plants rest on bedrock, and a de-watering system is not relied upon to control settlement.

For item 3.5.1-2, the applicant stated that this item is not applicable because BBS do not have any porous concrete subfoundations, therefore, this aging effect and mechanism is not applicable. The staff evaluated the applicant's claim and finds it acceptable because the GALL Report recommendation to manage the aging effect of reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation only applies to porous subfoundations, which do not exist at BBS.

Reduction of Strength and Modulus Due to Elevated Temperature. LRA Section 3.5.2.2.1.2, associated with LRA Table 3.5.1, item 3.5.1-3, addresses reduction of strength and modulus due to elevated temperatures in concrete exposed to air-indoor, uncontrolled or air-outdoor. The criteria in SRP-LR Section 3.5.2.2.1.2 state that the GALL Report recommends a plant-specific AMP if any portion of the concrete containment components exceeds the temperature limits specified in Subsection CC-3400 of ASME Code, Section III, Division 2, (i.e., 66 °C (150 °F)) for general areas, and 93 °C (200 °F) for local areas. The applicant stated that this item is not applicable because the containment concrete temperatures are maintained below the GALL Report limits stated above. The staff reviewed LRA Section 2.4.1, Section 3.5, and the UFSAR to evaluate the applicant's claim and finds it acceptable because the concrete containment components within the scope of license renewal are not exposed to elevated temperatures above those specified in Subsection CC-3440 of ASME Code Section III, Division 2. Therefore, a plant-specific AMP is not required, and further evaluation of this aging effect is not necessary.

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

Item 1. LRA Section 3.5.2.2.1.3 is associated with LRA Table 3.5.1, items 3.5.1-4 and 3.5.1-5. Item 3.5.1-4 is associated with BWRs only, so it is not applicable to BBS. Item 3.5.1-5 addresses steel elements of inaccessible areas of the containment liner exposed to air – indoor, uncontrolled which will be managed for loss of material due to general, pitting, and crevice corrosion by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs. The criteria in SRP-LR Section 3.5.2.2.1.3, item 1, state that loss of material due to general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to manage this aging effect. The SRP-LR also states that the GALL Report recommends further evaluation of plant-specific programs to manage this aging effect if corrosion is indicated from the IWE examinations. The GALL Report states that additional plant-specific activities are warranted if loss of material due to corrosion is significant for inaccessible areas (embedded containment steel shell or liner). The GALL Report states that loss of material due to corrosion is not significant if the following conditions are satisfied:

- Concrete meeting the requirements of ACI 318 or 349 and the guidance of 201.2R was used for the concrete in contact with the embedded containment shell or liner.
- The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements.

- 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.
- Borated water spills and water ponding on the concrete floor are cleaned up or diverted to a sump in a timely manner.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that further evaluation was warranted because IWE examinations have indicated corrosion of the steel liner. The applicant stated that it identified corrosion at Braidwood when the ASME Section XI, Subsection IWE program was first implemented in 1999 and 2000. At that time, the applicant recoated damaged areas where there was containment liner corrosion with the same zinc-rich coating. Subsequent followup inspections identified coating degradation and corrosion at recoated areas; the applicant attributed this to an event in which the surface preparation was inadequate prior to the first recoating. The LRA states that the applicant plans to make weld repairs to the liners in localized areas to restore the liners to their nominal thickness during the 2013 and 2014 refueling outages. The staff noted during an onsite audit, as documented in the staff's audit report, that the applicant is currently using an augmented inspection program in accordance with the ASME Section XI, Subsection IWE requirements.

The applicant also addressed the GALL Report recommendations to determine if additional plant-specific activities, in addition to those performed as part of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs, are warranted to manage significant corrosion for inaccessible areas of the steel liner. In LRA Section 3.5.2.2.1.3, the applicant addressed the criteria for significant corrosion as stated in the GALL Report. In part:

- Concrete meeting the requirements of ACI 318 and the guidance of ACI 201.2R with respect to chlorine ion content was used for the containment concrete in contact with the embedded containment liner. This ensures that the contact with the containment or basemat will not cause corrosion of the liner, liner anchors, or other steel elements embedded in the concrete.
- The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements.
- Interior and exterior surfaces of the containment structures are monitored by the ASME Section XI, Subsection IWL and Structures Monitoring programs to ensure that the concrete is free of penetrating cracks that provide a path for water seepage to an inaccessible surface of the containment liner. If any penetrating cracks that could provide a path for water seepage to an inaccessible surface of containment liner are identified, the condition is entered in the corrective action program and the concrete cracks are accepted by evaluation or repaired.
- Borated water leakage is managed in accordance with the Boric Acid Corrosion Program.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWE, 10 CFR Part 50, Appendix J, and Boric Acid Corrosion programs is documented in SER Sections 3.0.3.2.16, 3.0.3.1.14, and 3.0.3.1.2, respectively. Following this review and review of the UFSAR, the staff noticed:

- The applicant meets criterion 1 because the concrete used was designed and constructed in accordance with the requirements of ACI 318. Additionally, ACI 301 incorporates the recommendations of ACI 201.2R, so the containment concrete design and construction is consistent with the GALL Report recommendations.

- The applicant meets criterion 2 because the IWE program inspects 100 percent of the moisture barrier at each inspection interval in accordance with ASME Section XI, Subsection IWE requirements.
- The applicant meets criterion 4 because the Boric Acid Corrosion Program ensures borated water spills are not common; and because if they occur, they are cleaned up in a timely matter.

In its review of the applicant's evaluation for criterion 3, the staff noticed that there is plant-specific OE with regards to aggressive groundwater infiltration through the exterior of the concrete containment at Byron Units 1 and 2. The staff needed additional information about whether there is a potential for water to migrate through cracks in the concrete or leach through the concrete itself, accumulate, and cause accelerated corrosion at the exterior face of the steel liner plate during the period of extended operation. By letter dated March 18, 2014, the staff issued RAI B.2.1.29-1 requesting information on how the program will ensure this does not contribute to a loss of material of the steel liner. The staff evaluated the applicant's response to RAI B.2.1.29-1 (submitted by letter dated April 17, 2014) and determined that the applicant's program is adequate to manage aging for the inaccessible exterior face of the containment liner. The staff's concerns and evaluation are documented in Section 3.0.3.2.16 of this SER. Upon review of the applicant's response to RAI B.2.1.29-1, the staff noticed that the applicant meets criterion 3, because the ASME Section XI, Subsection IWL and Structures Monitoring Programs include visual inspections to ensure that the concrete is free of penetrating cracks that provide a path for water seepage to an inaccessible surface of the containment liner. The programs will also ensure that any penetrating cracks that could provide a path for water seepage to an inaccessible surface of containment liner are identified, the condition is entered in the CAP, and the concrete cracks are accepted by evaluation or repaired. With regards to the possible moisture inleakage through the Containment, the staff noticed that the Structures Monitoring Program is enhanced to include actions to evaluate the condition of the reinforced concrete in the tendon tunnels and evaluate for any potential impacts to the containment liner, as well as execute any necessary corrective actions to ensure that the liner continues to maintain its ability to perform its intended function.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs is documented in SER Sections 3.0.3.2.16 and 3.0.3.1.14, respectively. The staff noticed that the programs ensure that corrosion of the containment liner is detected and corrective actions taken before there is a loss of material that affects the ability of the containment liner to perform its function by utilizing visual examinations of accessible areas of the liner at frequencies required by the ASME Code and applicable regulations. Augmented examinations of the containment liner, including inaccessible areas, are required if there are indications in accessible areas that degradation of inaccessible areas could also be occurring. The staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program is acceptable because the programs will manage aging of inaccessible areas of the containment liner by monitoring 100 percent of the accessible areas of the containment liner, including examination of 100 percent of the moisture barrier at the interface between the accessible and inaccessible steel and ensuring that the containment liner leak tightness is in accordance with 10 CFR Appendix J. In addition, the applicant meets all four criteria for which the GALL Report recommends that corrosion is not significant.

Based on the programs identified, the staff determines that the applicant's programs meet SRP-LR Section 3.5.2.2.1.3, item 1 criteria. For those items associated with LRA Section 3.5.2.2.1.3, item 1, the staff concludes that the LRA is consistent with the GALL Report and that the applicant 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).

Item 2. LRA Section 3.5.2.2.1.3, associated with LRA Table 3.5.1, item 3.5.1-6, addresses loss of material due to general, pitting, and crevice corrosion in steel torus shell of Mark I containments. The criteria in SRP-LR Section 3.5.2.2.1.3, item 2, refers to steel torus shell of Mark I containments. The applicant stated that this item is not applicable because this component is applicable only to BWRs. The staff evaluated the applicant's claim and finds it acceptable because BBS are PWRs.

Item 3. LRA Section 3.5.2.2.1.3, associated with LRA Table 3.5.1, item 3.5.1-7, addresses loss of material due to general, pitting, and crevice corrosion in steel torus shell of Mark I containments. The criteria in SRP-LR Section 3.5.2.2.1.3 item 3 refers to steel torus shell of Mark I containments. The applicant stated that this item is not applicable because this component is applicable only to BWRs. The staff evaluated the applicant's claim and finds it acceptable because BBS are PWRs.

Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature. LRA Section 3.5.2.2.1.4, associated with LRA Table 3.5.1, item 3.5.1-8, states that loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for prestressed concrete containments is a TLAA evaluated in accordance with 10 CFR 54.21(c) and that the evaluation of this TLAA is addressed in LRA Section 4.5, Concrete Containment Tendon Prestress Analysis. This is consistent with SRP-LR Section 3.5.2.2.1.4 and is, therefore, acceptable. The staff's evaluation of the TLAA for loss of containment tendon prestress is documented in SER Section 4.5.

Cumulative Fatigue Damage. LRA Section 3.5.2.2.1.5, associated with LRA Table 3.5.1, item 3.5.1-9, states that TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1) and that the evaluation of this TLAA is addressed in Section 4.6, "Containment Liner Plates, Metal Containments, and Penetrations Fatigue Analysis." This is consistent with SRP-LR Section 3.5.2.2.1, item 5, and is therefore, acceptable. The staff's evaluation of the TLAA for the BBS containment penetration sleeves, penetration bellows, and containment hatches and liner is documented in SER Section 4.6.

LRA Section 3.5.2.2.2.5, which is associated with LRA Table 3.5.1, item 3.5.1-53, addresses cumulative fatigue damage due to cyclic loading in component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue of Group B1.1 component supports is a TLAA, as defined in 10 CFR 54.3 and that fatigue of Group B1.1 component supports are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Section 4.3.

The staff reviewed LRA Section 3.5.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.5, which states that fatigue of these structural 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). The staff reviewed the applicant's AMR line items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage for these structural components.

The applicant also stated that based on its reviews to identify TLAAs in the CLB, there are no other fatigue analyses for component support members for Groups B1.2 and B1.3. The staff reviewed the applicant's UFSAR and confirmed that the applicant's CLB does not contain fatigue analyses for component support members, anchor bolts, and welds for Groups B1.2 and B1.3 that are required to be identified as TLAAs in accordance with 10 CFR 54.21(c)(1). Therefore, the staff finds the applicant's claim acceptable.

The staff concludes that the applicant has met the SRP-LR Section 3.5.2.2.2.5 criteria. For those line items that apply to LRA Section 3.5.2.2.2.5, the staff determined that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these structural components.

<u>Cracking Due to Stress Corrosion Cracking</u>. LRA Section 3.5.2.2.1.6, associated with LRA item 3.5.1-10, addresses SS penetration sleeves, penetration bellows, and dissimilar metal welds exposed to plant indoor air which will be managed for cracking due to SCC by the ASME Section XI, Subsection IWE program and 10 CFR 50, Appendix J program. The criteria in SRP-LR Section 3.5.2.2.1.6 state that cracking due to SCC of SS penetration bellows and dissimilar metal welds could occur in all types of PWR and BWR containments. The SRP-LR also states that the existing program relies on ASME Section XI, Subsection IWE program and 10 CFR Part 50, Appendix J program to manage this aging effect. The GALL Report recommends further evaluation of additional appropriate examinations/evaluations implemented to detect cracking due to SCC for SS penetration components and dissimilar metal welds.

As described above, the applicant stated that LRA item 3.15.1-10 is applicable to the BBS and cracking due to SCC of the containment SS penetration components are managed by the existing ASME Section XI, Subsection IWE program and 10 CFR Part 50, Appendix J program, as recommended in the GALL Report. The applicant also stated that the aging management evaluation for this item determined cracking due to SCC of these components is not expected to occur because SCC requires a concentration of chloride or sulfate contaminants which are not normally present in significant quantities at these components as well as high stresses and temperatures greater than 140 °F (60 °C). The applicant further stated that the TSs limit the average air temperature inside the containment during normal plant operation up to 120 °F (49 °C).

In its review, the staff finds that the applicant's aging management for the SS penetration components acceptable because the applicant confirmed that (1) the normal operating temperature inside the containment is limited up to 120 °F, which is below the threshold temperature for SCC, (2) the environment is not conducive to SCC, and (3) the existing ASME Section XI, Subsection IWE program and 10 CFR 50, Appendix J program are used to confirm that SCC does not affect the integrity of the containment penetration components.

The staff's evaluations of the applicant's ASME Section XI, Subsection IWE program and 10 CFR 50, Appendix J program are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.14, respectively. In its review of components associated with LRA item 3.5.1-10, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWE program and 10 CFR 50, Appendix J program is acceptable because the applicant's evaluation confirmed that (1) the normal operating temperature inside the containment, which does not exceed 120 °F, is not conducive to SCC, (2) the environment without chemical contamination is not conducive to SCC, and (3) the ASME Section XI, Subsection IWE program and 10 CFR 50, Appendix J program will continue to confirm that cracking due to SCC does not affect the integrity of the SS penetration components.

The staff determines that the applicant's programs and aging management evaluation meet the SRP-LR Section 3.5.2.2.1.6 criteria. For those items associated with LRA Section 3.5.2.2.1.6, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

<u>Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw</u>. LRA Section 3.5.2.2.1.7, associated with LRA Table 3.5.1, item 3.5.1-11, addresses inaccessible areas of concrete containments located in moderate to severe weathering conditions exposed to air-outdoor or groundwater/soil which will be managed for loss of material (scaling, spalling) and cracking due to freeze-thaw by the ASME Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1.7 state that loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The SRP-LR also states that a plant-specific AMP is not required if documented evidence confirms that the existing concrete had air entrainment content between 3 and 8 percent, and subsequent inspections of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the containment structures are designed in accordance with ACI 318 and constructed in accordance with ACI 301; air entrainment content is per design requirements of ACI 211.1 to produce durable concrete against freeze-thaw. The applicant stated that a plant-specific aging management is not required because the containment concrete mix design meets the air content requirements of between 3 and 8 percent, and OE review has not identified significant loss of material (scaling, spalling) and cracking in accessible areas of the containment structure. The applicant further stated that the ASME Section XI, Subsection IWL Program will be used to manage this aging effect or mechanism for inaccessible areas of the containment in an air-outdoor environment. If significant degradation due to freeze-thaw is identified by visual inspection of accessible areas, corrective actions will be initiated to evaluate the acceptability of inaccessible areas. In addition, exposed portions of below-grade concrete will be examined when excavated for any reason.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The staff reviewed UFSAR Section 3.8.1.6 and Appendix B.1.3 and confirmed that appropriate air entrainment was used in the concrete mix design. The staff's review of the OE did not identify any significant freeze-thaw-related concrete degradation of accessible areas of BBS containment structures; thereby a plant-specific program to manage this aging effect is unnecessary. Nevertheless, the staff noticed that the applicant will continue to use the ASME Section XI, Subsection IWL Program to monitor aging effects due to freeze-thaw, which is consistent with the GALL Report for accessible areas. The staff also noticed that the applicant cited generic Note E in LRA Table 3.5.2-4 for components associated with item 3.5.1-11 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect or mechanism. In its review of components associated with item 3.5.1-11, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWL Program is acceptable because periodic visual inspections of the accessible areas of the containment structure, performed under the ASME Section XI, Subsection IWL Program, are capable of detecting a loss of material (scaling, spalling) and cracking due to freeze-thaw. In the event that unacceptable conditions are identified, corrective actions will be initiated to evaluate the acceptability of inaccessible areas.

Based on the program identified, the staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.1.7 criteria. For those items associated with LRA Section 3.5.2.2.1.7, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions 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 Expansion from Reaction with Aggregates</u>. LRA Section 3.5.2.2.1.8, associated with LRA Table 3.5.1, item 3.5.1-12, addresses cracking due to expansion from reaction with aggregates in inaccessible areas of concrete elements exposed to any environment. The criteria in SRP-LR Section 3.5.2.2.1.8 state that a plant-specific AMP is not necessary if investigations, tests, and petrographic examination of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests, as required, can demonstrate that those aggregates do not adversely react within concrete; or for potentially reactive aggregates, aggregate concrete reaction is not significant if it is demonstrated that the inplace concrete can perform its intended function. The applicant stated that the aging effect and mechanism does not apply to Byron and Braidwood containment structures because the fine and coarse aggregates used conform to ASTM C33; petrographic examination and reactivity tests of aggregates were performed in accordance with ASTM C295 and ASTM C289, respectively; the structures and concrete structures were constructed in accordance with ACI 318. The aging effect or mechanism has not been observed on BBS concrete structures, including containments. The applicant thereby concluded for several LRA Table 3.5.1 items (3.5.1-12, -19, -43, -50, and -54) associated with this aging effect or mechanism that no aging management or further evaluation of accessible concrete areas or below-grade inaccessible concrete areas is required for this mechanism. As such, the applicant did not provide any AMR results line items for this aging effect or mechanism in any of the Table 2s in LRA Section 3.5.2.

In its review of components associated with LRA items 3.5.1-12 and 3.5.1-19, the staff evaluated the applicant's nonapplicability claim for cracking due to expansion from reaction with aggregates and requested additional information because the applicant did not provide adequate plant-specific technical basis to support its statement, and because, as stated in NRC IN 2011-20, the tests described in ASTM C227 and ASTM C289 may not accurately predict aggregate reactivity, especially when dealing with late-expanding or slow-expanding aggregates containing strained quartz or microcrystalline quartz. Further, in light of the industry OE at Seabrook Station, unless positively justified, cracking due to expansion from reaction with aggregates could occur in concrete in both accessible and inaccessible areas and should be managed through the period of extended operation. Therefore, by letter dated May 19, 2014, the staff issued RAI 3.5.2.2.1-1 that covered the LRA items 3.5.1-12, -19, -43, -50, and -54, associated with the alkali-aggregate reaction aging effect or mechanism. Through RAI 3.5.2.2.1-1, the staff requested the applicant to provide technical justification why cracking due to expansion from reaction with aggregates (i.e., alkali-aggregate reaction) does not require management for concrete in accessible and inaccessible areas or to identify applicable program(s) to manage this aging effect and update applicable LRA sections accordingly.

In its response dated June 9, 2014, specifically with regard to LRA items 3.5.1-19 (applies to concrete pressure-resisting components in accessible areas) and 3.5.1-12 (applies to concrete pressure-resisting components in inaccessible areas) for containment structures, the applicant stated that the cracking aging effect of reinforced concrete, which includes cracking due to reaction with aggregates, is managed by the ASME Section XI, Subsection IWL Program, which is consistent with the GALL Report recommendation for accessible areas. The applicant revised LRA Table 3.5.1, item 3.5.1-19 (concrete (accessible areas): dome; wall; basemat; ring girders; buttresses corresponding to GALL Report item II.A1.CP-33) to indicate applicability and consistency of the aging effect or mechanism and program with the GALL Report and that the ASME Section XI, Subsection IWL Program will be used to manage the aging effect or mechanism in the accessible concrete containment pressure-resisting components for any environment. The applicant also revised the LRA Table 3.5.2-4 for the containment structure to include AMR results line items that reference LRA item 3.5.1-19.

Further, the applicant revised LRA Table 3.5.1, item 3.5.1-12 (concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses corresponding to GALL Report item II.A1.CP-67) and LRA Section 3.5.2.2.1.8 to state that accessible concrete surfaces that are part of the containment pressure boundary are monitored for cracking due to expansion from reaction with aggregates by the ASME Section XI, Subsection IWL Program as addressed under LRA item 3.5.1-19. In addition, other accessible containment concrete not part of the pressure boundary is monitored for this aging effect or mechanism by the Structures Monitoring Program as addressed under LRA item 3.5.1-54. The applicant stated that both these programs require evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The applicant further stated that the condition of accessible concrete is used as an indicator for evaluating the condition of inaccessible and below-grade concrete areas. The applicant concluded that a plant-specific AMP is not necessary because BBS concrete was constructed to the recommended standards to preclude this aging effect or mechanism.

The staff finds the applicant’s response acceptable with regard to LRA items 3.5.1-12 and 3.5.1-19 for concrete components of containment structures in accessible and inaccessible areas because the applicant stated that cracking due to expansion from reaction with aggregates is applicable, identified appropriate program(s) to manage it, and revised the applicable LRA sections accordingly. Therefore, the staff’s concern described in RAI 3.5.2.2.1-1, with regard to LRA items 3.5.1-12 and 3.5.1-19 for accessible and inaccessible concrete components in containment structures, is resolved. The staff notes that its evaluation of LRA Table 3.5.1, item 3.5.1-54 is provided in SER Section 3.5.2.2.2.

The staff’s evaluation of the applicant’s ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The staff noticed that a plant-specific AMP is not necessary because the BBS concrete containment structures were constructed to recommended ACI and ASTM standards that minimize the possibility of cracking due to alkali-aggregate reaction, and review of the OE did not identify the aging effect or mechanism in accessible portions of BBS concrete structures. The staff noticed, in the response to RAI 3.5.2.2.1-1, that the applicant proposed to use the ASME Section XI, Subsection IWL Program to manage the aging effect or mechanism which is consistent with the GALL Report recommendation for this aging effect in accessible areas. GALL Report AMP XI.S2 requires periodic visual inspections of accessible concrete surfaces, by qualified personnel, at an interval not to exceed 5 years, to manage the effects of aging. In its review of components associated with item 3.5.1-12, as amended by letter dated June 9, 2014, the staff finds that the applicant has met the further evaluation criteria and that the applicant’s proposal to manage the effects of aging using the ASME Section XI, Subsection IWL Program is acceptable because the program is consistent with the GALL Report recommendation to manage cracking from expansion due to reaction with aggregates by periodic visual inspections of accessible areas of containment structures and will use conditions identified in accessible areas as the leading indicator to evaluate the acceptability of the aging effect in inaccessible areas of affected structures in the CAP.

Based on the program identified, the staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.1.8 criteria. For those items associated with LRA Section 3.5.2.2.1.8, as amended by letter dated June 9, 2014, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation. LRA Section 3.5.2.2.1.9, associated with LRA Table 3.5.1, item 3.5.1-13 and item 3.5.1-14, addresses increase in porosity and permeability due to leaching of calcium hydroxide and carbonation in inaccessible areas of concrete containment in PWRs and BWRs exposed to flowing water. The criteria in SRP-LR Section 3.5.2.2.1.9 state that further evaluation is recommended if leaching is observed in accessible areas. The SRP-LR also states that a plant-specific AMP is not required if (1) there is evidence in accessible areas that the flowing water has not caused leaching and carbonation or (2) evaluation determined that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on the intended function of the concrete structure. The applicant stated that LRA Section 3.5.2.2.1.9 related to Table 3.5-1, item 3.5.1-13, is not applicable to the BBS containment because it has prestressed concrete structures. The staff evaluated the applicant's claim and finds it acceptable because this item is relevant only to PWR steel containments and BWR containments.

The applicant addressed the further evaluation criteria of the SRP-LR for LRA item 3.5.1-14 by stating that BBS containment structures are designed and constructed in accordance with ACI 318 and ACI 301 standards to produce durable concrete resistant to leaching. The staff noticed that the applicant's review of OE at BBS found that increase in porosity and permeability, and loss of strength is not significant at BBS, and that it is being adequately managed by ASME Section XI, Subsection IWL and Structures Monitoring Programs. However, the staff also noticed that in response to RAI B.2.1.30-1 and B.2.1.34-1, the applicant addressed the staff's concerns regarding water in-leakage into the tendon tunnels and committed to perform confirmatory activities associated with evaluating the condition of the concrete that has been subject to water in-leakage. The staff's evaluations of these RAI responses are documented in SER Sections 3.0.3.2.17 and 3.0.3.2.20, respectively.

The staff's evaluations of the applicant's ASME Section XI, Subsection IWL and Structures Monitoring Programs are documented in SER Sections 3.0.3.2.17 and 3.0.3.2.20, respectively. The staff reviewed the plant UFSAR Section 3.8.1 for applicable codes and Appendix B.1 for concrete material standards, concrete and testing procedures, and confirmed the characteristic properties of the concrete mix. ACI 318 requirements for concrete design, placement, and curing ensure durability and strength of concrete. Further, because the BBS OE has not indicated significant aging effect or mechanism, a plant-specific AMP is unnecessary. The staff noticed that the applicant cited generic Note E in LRA Table 3.5.2-4 for components associated with item 3.5.1-14 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect or mechanism. In its review of components associated with item 3.5.1-14, the staff finds that the applicant has met the further evaluation criteria; and that the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWL and Structures Monitoring Programs is acceptable because periodic visual inspections by qualified personnel will detect indications of leaching and carbonation in accessible areas, and because these programs will require the evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

The staff determines that the applicant's programs meet the SRP-LR Section 3.5.2.2.1.9 criteria. For those items associated with LRA Section 3.5.2.2.1.9, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions 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

Aging Management of Inaccessible Areas. The staff reviewed LRA Section 3.5.2.2.2.1 which addresses further evaluations recommended by SRP-LR Section 3.5.2.2.2.1 related to aging management of below-grade inaccessible areas of Groups 1–3, 5, and 7–9 structures for aging effects as below.

Item 1. LRA Section 3.5.2.2.2.1.1, associated with LRA Table 3.5.1, item 3.5.1-42, addresses below-grade inaccessible concrete areas of Groups 3 and 5 structures exposed to outdoor air, for plants located in moderate to severe weathering conditions, which will be managed for loss of material (spalling, scaling) and cracking due to freeze-thaw by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 1, state that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur for below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 exposed to outdoor air and that the GALL Report recommends further evaluation for plants located in moderate to severe weathering conditions. The SRP-LR also states that a plant-specific AMP is not required if documented evidence confirms that the existing concrete had air entrainment content between 3 and 8 percent, and subsequent inspection of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the BBS concrete requiring freeze-thaw resistance meets the air content requirement of between 3 and 8 percent, and plant OE has not identified significant aging effects related to freeze-thaw in accessible areas of Groups 3 and 5 concrete structures and that the Structures Monitoring Program will be used to manage this aging effect in both accessible and inaccessible areas by performing inspections of accessible areas. The applicant further stated that if degradation of concrete due to freeze-thaw is identified in accessible areas of the structures, corrective action will be initiated to evaluate acceptability of inaccessible portions of structures. In addition, exposed portions of below-grade concrete will be examined by the enhanced Structures Monitoring Program when excavated for any reason.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff reviewed UFSAR Section 3.8.4.6 and Appendix B.1.3 and confirmed that appropriate air entrainment was used in the concrete mix design. The staff's review of the OE did not identify any significant freeze-thaw-related concrete degradation for Groups 3 and 5 structures at BBS; thereby, a plant-specific program to manage this aging effect is unnecessary. Nevertheless, the staff noticed that the applicant will use the enhanced Structures Monitoring Program to monitor aging effects due to freeze-thaw for Groups 3 and 5 structures. The staff also noticed that the applicant cited generic Note E in the Table 2s for components associated with item 3.5.1-42 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect. In its review of components associated with item 3.5.1-42, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the enhanced Structures Monitoring Program is acceptable because (1) the program is capable of monitoring and managing aging effects due to freeze-thaw by performing periodic visual inspections of accessible areas of Groups 3 and 5 structures by qualified personnel at intervals not to exceed 5 years, (2) the program will use significant freeze-thaw degradation identified in accessible areas as the leading indicator to evaluate the acceptability of the aging effect in inaccessible areas of affected structures in the CAP, and (3) a plant-specific program is unnecessary.

The staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.2.1, item 1 criteria. For those items associated with LRA Section 3.5.2.2.2.1.1, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 2. LRA Section 3.5.2.2.2.1.2, associated with LRA Table 3.5.1, item 3.5.1-43, addresses cracking due to expansion from reaction with aggregates in inaccessible concrete areas exposed to any environment for structures of all groups except Group 6 structures. The criteria in SRP-LR Section 3.5.2.2.2.1, item 2, states that further evaluation is recommended to determine if a plant-specific AMP is required to manage this aging effect. The SRP-LR also states that a plant-specific program is not required if (1) investigations, tests, and petrographic examination of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests, as required, can demonstrate that those aggregates do not adversely react within reinforced concrete, or (2) for potentially reactive aggregates, aggregate concrete reaction is not significant if it can be demonstrated that the inplace concrete can perform its intended function. The applicant addressed the further evaluation criteria by stating that the aging effect and mechanism covered by this item is not applicable to BBS concrete structures because the fine and coarse aggregates used in the concrete conform to ASTM C33, petrographic examination and reactivity tests of aggregates were performed in accordance with ASTM C295 and ASTM C289, respectively, the concrete structures were constructed in accordance with ACI 318, and the aging effect or mechanism has not been observed on accessible portions of BBS concrete structures. The applicant thereby concluded for several LRA Table 3.5.1 items (3.5.1-43, -50, -54, -12, and -19) associated with this aging effect or mechanism that no aging management or further evaluation of accessible concrete areas or below-grade inaccessible concrete areas is required for this mechanism. As such, the applicant did not provide any AMR results line items for this aging effect or mechanism in any of the Table 2s in LRA Section 3.5.2.

In its review of components associated with item 3.5.1-43, the staff evaluated the applicant's nonapplicability claim for cracking due to expansion from reaction with aggregates and requested additional information because the applicant did not provide adequate plant-specific technical basis to support its statement and, as stated in NRC IN 2011-20, the tests described in ASTM C227 and ASTM C289 may not accurately predict aggregate reactivity, especially when dealing with late-expanding or slow-expanding aggregates containing strained quartz or microcrystalline quartz. Further, in light of the industry OE at Seabrook Station, unless positively justified, cracking due to expansion from reaction with aggregates could occur in concrete in both accessible and inaccessible areas and should be managed through the period of extended operation. Therefore, by letter dated May 19, 2014, the staff issued RAI 3.5.2.2.1-1 that covered the LRA items 3.5.1-43, -50, -54, -12, and -19, associated with the alkali-aggregate reaction aging effect or mechanism. Through RAI 3.5.2.2.1-1, the staff requested the applicant to provide technical justification why cracking due to expansion from reaction with aggregates (i.e., alkali-aggregate reaction) does not require management for concrete in accessible and inaccessible areas or to identify applicable program(s) to manage this aging effect and update applicable LRA sections accordingly.

In its response dated June 9, 2014, specifically with regard to LRA items 3.5.1-54 (concrete accessible areas) and 3.5.1-43 (concrete inaccessible areas)) for structures of all groups except Group 6, the applicant stated that the cracking aging effect of reinforced concrete, which includes cracking due to reaction with aggregates, is managed by the Structures Monitoring Program, which is consistent with the GALL Report recommendation for accessible areas. The applicant revised LRA Table 3.5.1 item 3.5.1-54 (all groups except 6: concrete (accessible areas): all) to indicate applicability and consistency of the aging effect or mechanism/program with the GALL Report and that the Structures Monitoring Program will be used to manage the aging effect or mechanism in accessible areas for structures of all groups except Group 6 for all applicable environments. The applicant also revised the applicable Table 2s for these structures to include AMR results line items that reference LRA item 3.5.1-54.

Further, the applicant revised LRA Table 3.5.1, item 3.5.1-43 (all groups except 6: concrete (inaccessible areas): all) and LRA Section 3.5.2.2.2.1.2 to state that accessible concrete is monitored for cracking due to expansion from reaction with aggregates by the Structures Monitoring Program as addressed under LRA item 3.5.1-54. The applicant stated that this program requires evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The applicant further stated that the condition of accessible concrete is used as an indicator for the condition of inaccessible areas and that the AMP will also examine portions of below-grade concrete when excavated for any reason. The applicant concluded that a plant-specific AMP is not necessary because BBS concrete was constructed to the recommended standards to preclude this aging effect or mechanism.

The staff finds the applicant’s response acceptable with regard to LRA items 3.5.1-43 and 3.5.1-54 for structures of all groups except 6 because the applicant stated that cracking due to expansion from reaction with aggregates is applicable, identified an appropriate program to manage it, and revised the applicable LRA sections accordingly. Therefore, the staff’s concern described in RAI 3.5.2.2.1-1, with regard to LRA items 3.5.1-43 and 3.5.1-54 for structures of all groups except 6, is resolved.

The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff noticed that a plant-specific AMP is not necessary because the BBS concrete structures were constructed to recommended ACI and ASTM standards that minimize the possibility of cracking due to alkali-aggregate reaction and review of the OE did not identify the aging effect or mechanism in accessible portions of BBS concrete structures. The staff noticed, in the response to RAI 3.5.2.2.1-1, that the applicant proposed to use the Structures Monitoring Program to effectively manage the aging effect which is consistent with the GALL Report recommendation for this aging effect in accessible areas. GALL Report AMP XI.S6 recommends using periodic visual inspections, by qualified personnel, at an interval not to exceed 5 years, to manage the effects of aging. The staff finds that the applicant has met the further evaluation criteria, and that the applicant’s proposal to manage the effects of aging using the Structures Monitoring Program is acceptable because (1) the program will effectively manage cracking from expansion due to reaction with aggregates by performing periodic visual inspections of accessible areas of structures of all groups except 6 at intervals not to exceed 5 years, (2) the program will use conditions identified in accessible areas as the leading indicator to evaluate the acceptability of the aging effect in inaccessible areas of affected structures in the CAP, and (3) a plant-specific program is unnecessary.

Based on the evaluation provided and program identified, the staff determines that the applicant's programs meet the SRP-LR Section 3.5.2.2.2.1, item 2, criteria. For those items associated with LRA Section 3.5.2.2.2.1.2 and LRA item 3.5.1-43, as amended by letter dated June 9, 2014, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 3. LRA Section 3.5.2.2.2.1.3, associated with LRA Table 3.5.1, items 3.5.1-44, 3.5.1-45, and 3.5.1-46, addresses below-grade inaccessible concrete areas of structures for all groups exposed to soil or flowing water which will be managed for cracking and distortion due to increased stress levels from settlement and reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 3, states that cracking and distortion due to increased stress levels from settlement, and reduction of foundation strength could occur in below-grade inaccessible concrete areas exposed to soil or flowing water and that further evaluation is necessary if a dewatering system is relied upon to control settlement to verify continued functioning of the dewatering system through the period of extended operation. The applicant addressed the further evaluation criteria of the SRP-LR for item 3.5.1-44 by stating that BBS does not rely upon a dewatering system to control settlement and, even though the aging effect has not been observed at BBS, the Structures Monitoring Program will be used to manage cracking and distortion due to any mechanism for below-grade exterior and foundation concrete, equipment supports, manholes, handholes, and duct banks exposed to groundwater and soil by evaluating the aging effects in inaccessible areas based on conditions found from inspection of accessible areas. The applicant addressed the further evaluation criteria of the SRP-LR for item 3.5.1-45 by stating that this item is not applicable because the structural component addressed in the item applies only to BWRs and is not used for BBS. The applicant also addressed the further evaluation criteria of the SRP-LR for item 3.5.1-46 by stating that the aging effect is not applicable because BBS structures are not founded on porous concrete subfoundation and does not rely upon a dewatering system to control settlement.

The staff reviewed the SRP-LR and the GALL Report and confirmed that line item III.A9.TP-31, which corresponds to LRA Table 3.5.1 item 3.5.1-45, is applicable only to BWR Unit Vent Stack and, therefore, does not apply to PWRs. The staff evaluated the applicant's claim that LRA Table 3.5.1 item 3.5.1-45 is not applicable and finds it acceptable because BBS is a PWR and the item does not apply to PWRs.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff reviewed UFSAR Sections 2.4.13.5 and 2.5.4.10 and confirmed that dewatering systems are not relied upon to control settlement and, therefore, LRA Table 3.5.1, items 3.5.1-44 and 3.5.1-46, do not need further evaluation. The staff noticed that the BBS structures are not founded on porous concrete subfoundations but generally founded on grouted bedrock or crushed rock. The staff evaluated the applicant's claim that the aging effect for LRA Table 3.5.1, item 3.5.1-46, is not applicable and finds it acceptable because the staff confirmed that the BBS concrete structures are not founded on porous concrete subfoundation and do not rely upon a dewatering system to control settlement. The staff also noticed that the applicant's proposal to continue use of the enhanced Structures Monitoring Program to manage cracking and distortion due to increased stress levels from settlement, based on evaluating the aging effects in inaccessible concrete areas using conditions observed from visual inspections of accessible areas, is consistent with the GALL Report recommendation and is therefore acceptable. In its review of components associated with item 3.5.1-44, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the Structures Monitoring Program is acceptable because the staff confirmed that the BBS structures do not rely upon a dewatering system to control settlement and because the Structures Monitoring Program proposed to manage the aging effect of cracking and distortion due to settlement is consistent with the GALL Report.

Based on the program identified, the staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.2.1, item 3, criteria. For those items associated with LRA Section 3.5.2.2.2.1.3, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 4. LRA Section 3.5.2.2.2.1.4 associated with LRA Table 3.5.1, item 3.5.1-47, addresses inaccessible concrete areas of Groups 3, 5, and 7 structures exposed to flowing water, which will be managed for increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 4, states that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible areas of Groups 1–5 and 7–9 concrete structures exposed to flowing water. The SRP-LR also states that further evaluation is required if leaching is observed in accessible areas that impact intended functions. The SRP-LR states that further evaluation is required to determine if a plant-specific AMP is needed to manage increase in porosity and permeability due to leaching of calcium hydroxide and carbonation of inaccessible concrete areas and that a plant-specific AMP is not required if (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation or (2) evaluation determined that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on the intended function of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that BBS concrete structures are designed and constructed in accordance with ACI standards to produce durable concrete, resistant to leaching. The applicant also stated that the effects of carbonation have not been observed on BBS concrete and that review of OE at BBS has found that increase in porosity and permeability and loss of strength due to leaching and carbonation are not significant and are adequately managed by the Structures Monitoring Program by visual inspection of accessible areas and exposed portions of inaccessible areas when excavated for any reason and by evaluation of aging effects in inaccessible areas based on conditions found in accessible areas.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff noticed that the applicant cited generic note E in the Table 2s for components associated with item 3.5.1-47 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect. In its review of components associated with item 3.5.1-47, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the Structures Monitoring Program is acceptable because this program is the

GALL-recommended program for managing the aging effects by visual inspection of accessible areas and evaluating inaccessible concrete areas based on conditions found in accessible areas, and because the BBS does not have OE of significant leaching or carbonation that would affect the intended function of the structure. Thus, an additional plant-specific program is not necessary.

The staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.2.1, item 4, criteria. For those items associated with LRA Section 3.5.2.2.2.1.4, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reduction of Strength and Modulus Due to Elevated Temperatures. LRA Section 3.5.2.2.2.2, associated with LRA Table 3.5.1, item 3.5.1-48, addresses reduction of strength and modulus due to elevated temperatures in concrete exposed to air-indoor, uncontrolled environment. The criteria in SRP-LR Section 3.5.2.2.2.2 states that further evaluation is recommended for any concrete that exceeds the temperature limits of 66 °C (150 °F) for general areas and 93 °C (200 °F) for local areas. This aging mechanism could occur in PWR and BWR Groups 1–5 concrete structures. The SRP-LR also states that higher temperatures may be allowed if tests and calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The applicant stated that this item is not applicable to BBS since Groups 1 and 2 structures do not exist for these sites and Groups 3 and 5 structures are not exposed to containment concrete temperatures above 150 °F per UFSAR Table 3.11-2. The refuel floor and spent fuel storage pool belong to Group 5 structures, and the spent fuel water temperature is maintained below 150 °F. The applicant also stated that for Group 4 structures, the internal containment average temperature is limited to 120 °F (49 °C). Also, high-energy line penetrations have been designed to limit surrounding concrete surfaces to temperatures less than 200 °F, except for the special pipe whip restraints that are located around each feedwater and main steam pipe as it passes through the concrete wall separating the MSIV room from the main steam tunnel. The applicant stated that design documents for the concrete at these pipe whip restraints include an evaluation for elevated temperatures, which determined that elevated temperatures up to 300 °F (149 °C) at the local areas of the pipes were acceptable.

The staff evaluated the applicant's claim, reviewed UFSAR Section 3.8.4, and did not find any discussion of an engineering evaluation that accounted for possible reductions in concrete strength or modulus of elasticity due to elevated temperature. Therefore, by letter dated April 24, 2014, the staff issued RAI 3.5.2.2.2.2-1 requesting that the applicant: (1) provide the maximum temperature that is experienced by the concrete walls of the MSIV room and MS tunnel near the special feedwater and main steam pipe whip restraints; (2) if the maximum local temperature experienced is greater than 200 °F, provide a discussion of the engineering evaluation that concluded the concrete would be able to perform its intended functions at elevated temperatures beyond GALL Report recommended limits; and (3) if the maximum local temperature experienced is greater than 200 °F, provide justification for why AMR line item 3.5.1-48 is not applicable to the MSIV room and MS tunnel concrete walls.

In its response dated May 23, 2014, the applicant stated in response to Part 1 of the RAI that the maximum local temperature recorded on the surface of the concrete walls of the MSIV room and MS tunnel near the special feedwater and main steam pipe whip restraints is 166 °F. The applicant also revised LRA Section 3.5.2.2.2.2 and Table 3.5-1, item 3.5.1-48, to state that the normal operating temperatures experienced on the concrete walls is not greater than 200 °F. In response to Parts 2 and 3 of the RAI, the applicant stated that the requests were not applicable since the maximum local temperatures experienced on the concrete walls are not greater than 200 °F.

The staff finds the applicant's response acceptable because the applicant clarified that the maximum temperature on the surface of the concrete walls of the MSIV room and MS tunnel near the special feedwater and main steam pipe whip restraints is 166 °F, which is less than the 200 °F specified in the GALL Report, and because the applicant made clarifying revisions to the appropriate LRA sections. Therefore, a plant-specific AMP is not required, and further evaluation of this aging effect is not necessary. The staff's concern described in RAI 3.5.2.2.2-1 is resolved. The staff thus finds that the applicant's claim, as amended by letter dated May 23, 2014, that the aging effect or mechanism is not applicable is acceptable because the concrete temperatures are within the limits recommended in the GALL Report.

<u>Aging Management of Inaccessible Areas for Group 6 Structures</u>. The staff reviewed LRA Section 3.5.2.2.2.3, which addresses further evaluations recommended in SRP-LR Section 3.5.2.2.2.3 related to aging management of inaccessible areas for Group 6 structures for aging effects as described below.

<u>Item 1</u>. LRA Section 3.5.2.2.2.3.1 associated with LRA Table 3.5.1, item 3.5.1-49, addresses inaccessible concrete areas of Group 6 structures exposed to outdoor air for plants located in moderate to severe weathering conditions, which will be managed for loss of material and cracking due to freeze-thaw by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The criteria in SRP-LR Section 3.5.2.2.2.3, item 1, state that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur for below-grade inaccessible concrete areas of Group 6 structures and recommend further evaluation for plants located in moderate to severe weathering conditions. The SRP-LR also states that a plant-specific program is not required if documented evidence confirms that the existing concrete had air entrainment content between 3 and 8 percent, and subsequent inspection of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the BBS concrete requiring freeze-thaw resistance meets the air content requirement of between 3 and 8 percent and plant OE has not identified significant aging effects related to freeze-thaw in accessible areas of Group 6 concrete structures, except at the Byron Essential Service Water Cooling Towers (SXCTs) in limited areas below the cooling tower fill. The applicant also stated that the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, with enhancements, which incorporate corrective action from the plant-specific OE of SXCTs, will be used to manage this aging effect in an outdoor air environment. The applicant further stated that the condition of accessible and above-grade concrete will be used as the leading indicator for the condition of inaccessible areas and, if degradation of concrete due to freeze-thaw is identified in accessible areas of the structures, corrective action will be initiated to evaluate acceptability of the aging effect in inaccessible portions of affected structures in the CAP.

The staff's evaluation of the applicant's enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is documented in SER Section 3.0.3.2.21. The staff reviewed UFSAR Section 3.8.4.6 and Appendix B.1.3 and confirmed that appropriate air entrainment was used in the concrete mix design. The staff review of the applicant's OE did not identify significant freeze-thaw-related concrete degradation, except in limited areas of the Byron SXCTs. The staff noticed that the applicant's enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power

Plants Program, will be used to manage this aging effect for Group 6 concrete structures. The staff also noticed that the applicant incorporated the plant-specific OE to manage the freeze-thaw degradation condition at the Byron SXCTs as enhancements to the program requiring inspections at increased frequency of every 3 years for the affected tower in general, every 1.5 years for fill support beams and air-inlet framing with observed local degradation, and to develop a repair plan to address degradation of SXCTs with specific emphasis for the fill beams. The staff noticed that the applicant cited generic Note E in the Table 2s for components associated with item 3.5.1-49 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect or mechanism. In its review of components associated with item 3.5.1-49, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, is acceptable because (1) the enhanced program will monitor and manage aging effects due to freeze-thaw of Group 6 structures by periodic visual inspections of accessible areas, (2) the program will use significant freeze-thaw degradation identified in accessible areas as the leading indicator to evaluate the acceptability of the aging effect in inaccessible areas, and (3) the program has incorporated and implemented enhancements and corrective action based on plant-specific OE.

Based on the program identified, the staff determines that the applicant's program meets the SRP-LR Section 3.5.2.2.2.3, item 1, criteria. For those items associated with LRA Section 3.5.2.2.2.3.1, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 2. LRA Section 3.5.2.2.2.3.2, associated with LRA Table 3.5.1, item 3.5.1-50, addresses cracking due to expansion from reaction with aggregates in inaccessible concrete areas of Group 6 structures exposed to any environment. The criteria in SRP-LR Section 3.5.2.2.2.3.2 states that further evaluation is recommended to determine if a plant-specific AMP is not required (1) if investigations, tests, and petrographic examination of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests, as required, can demonstrate that those aggregates do not adversely react within concrete; or (2) for potentially reactive aggregates, aggregate concrete reaction is not significant if it is demonstrated that the inplace concrete can perform its intended function. The applicant stated that the aging effect and mechanism does not apply to BBS Group 6 concrete structures because the fine and coarse aggregates used in the concrete conform to ASTM C33; petrographic examination and reactivity tests of aggregates were performed in accordance with ASTM C295 and ASTM C289, respectively; the structures were constructed in accordance with ACI 318; and the aging effect has not been observed on BBS concrete Group 6 structures. The applicant thereby concluded for several LRA Table 3.5.1 items (3.5.1-43, -50, -54, -12, and -19) associated with this aging effect or mechanism that no aging management or further evaluation of accessible concrete areas or below-grade inaccessible concrete areas is required for this mechanism. As such, the applicant did not provide any AMR results line items for this aging effect or mechanism in any of the Table 2s in LRA Section 3.5.2.

In its review of components associated with item 3.5.1-50, the staff evaluated the applicant's nonapplicability claim for cracking due to expansion from reaction with aggregates and requested additional information because the applicant did not provide adequate plant-specific technical basis to support its statement and, as stated in NRC IN 2011-20, the tests described in ASTM C227 and ASTM C289 may not accurately predict aggregate reactivity, especially when dealing with late-expanding or slow-expanding aggregates containing strained quartz or microcrystalline quartz. Further, in light of the industry OE at Seabrook Station, unless positively justified, cracking due to expansion from reaction with aggregates could occur in concrete in both accessible and inaccessible areas and should be managed through the period of extended operation. Therefore, by letter dated May 19, 2014, the staff issued RAI 3.5.2.2.1-1 that covered the LRA items 3.5.1-50, -54, -43, -12, and -19, associated with the alkali-aggregate reaction aging effect or mechanism. RAI 3.5.2.2.1-1 requested the applicant to provide technical justification why cracking due to expansion from reaction with aggregates (i.e., alkali-aggregate reaction) does not require management for concrete in accessible and inaccessible areas, or to identify applicable program(s) to manage this aging effect and update applicable LRA sections accordingly.

In its response dated June 9, 2014, with regard to LRA items 3.5.1-54 (concrete accessible areas) and 3.5.1-50 (concrete inaccessible areas) specifically for Group 6 structures, the applicant stated that the cracking aging effect of reinforced concrete, which includes cracking due to reaction with aggregates, is managed by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The applicant revised LRA Table 3.5.1, item 3.5.1-54 (all groups except 6: concrete (accessible areas): all) to indicate applicability and consistency of the aging effect or mechanism/program with the GALL Report and to indicate that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, will be substituted for the Structures Monitoring Program and used to manage the aging effect in accessible areas of Group 6 structures for all applicable environments. The applicant also revised the applicable Table 2s for these structures to include AMR results line items that reference LRA item 3.5.1-54 for Group 6 structures.

Further, the applicant revised LRA Table 3.5.1, item 3.5.1-50 (Group 6: concrete (inaccessible areas): all) and LRA Section 3.5.2.2.2.3.2 to state that accessible Group 6 concrete is monitored for cracking due to expansion from reaction with aggregates by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as addressed under LRA item 3.5.1-54. The applicant also stated that this program requires evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The applicant further stated that the condition of accessible concrete is used as an indicator for the condition of inaccessible areas and that the AMP will also examine portions of below-grade concrete when excavated for any reason. The applicant concluded that a plant-specific AMP is not necessary because BBS concrete was constructed to the recommended standards to preclude this aging effect.

The staff finds the applicant's response acceptable with regard to LRA items 3.5.1-50 and 3.5.1-54 for Group 6 because the applicant stated that cracking due to expansion from reaction with aggregates is applicable, identified an appropriate program to manage it, and revised the applicable LRA sections accordingly. Therefore, the staff's concern described in RAI 3.5.2.2.1-1, with regard to LRA items 3.5.1-50 and 3.5.1-54 for Group 6 structures, is resolved.

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 3.0.3.2.21. The staff noticed that a plant-specific AMP is not necessary because the BBS concrete structures were constructed to the recommended ACI and ASTM standards that minimize the possibility of cracking due to alkali-aggregate reaction and that review of the OE did not identify the aging effect or mechanism in accessible portions of BBS concrete structures. The staff noticed, in the

RAI 3.5.2.2.1-1 response, that the applicant proposed to use the enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, to manage this aging effect in accessible areas. The GALL Report recommends GALL Report AMP XI.S6, “Structures Monitoring,” to ensure that this aging effect is adequately managed; however, the staff notes that a GALL Report AMP was not identified for accessible areas of Group 6 structures. GALL Report AMP XI.S6 recommends using periodic visual inspections, by qualified personnel, at an interval not to exceed 5 years, to manage the effects of aging. The staff noticed that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, proposes to manage the effects of aging for concrete structures through periodic visual inspections by qualified personnel, at an interval not to exceed 5 years and are consistent inspections, in terms of inspection guidance and frequency, with the recommendations for visual inspections in the Structures Monitoring Program and is, therefore, considered consistent with the GALL Report. The staff also noticed that the applicant cited generic note E in the Table 2s for Group 6 structures for components associated with item 3.5.1-54 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect or mechanism. The staff finds that the applicant has met the further evaluation criteria, and that the applicant’s proposal to manage the effects of aging using the enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, is acceptable because (1) the program will monitor and manage cracking from expansion due to reaction with aggregates by periodic visual inspections of accessible areas of Group 6 structures, (2) the program will use conditions identified in accessible areas as the leading indicator to evaluate the acceptability of the aging effect in inaccessible areas of affected structures in the CAP, and (3) a plant-specific program is unnecessary.

Based on the evaluation provided and program identified, the staff determines that the applicant’s programs meet the SRP-LR Section 3.5.2.2.2.3, item 2, criteria. For those items associated with LRA Section 3.5.2.2.2.3.2 and LRA item 3.5.1-50, as amended by letter dated June 9, 2014, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 3. LRA Section 3.5.2.2.2.3.3 associated with LRA Table 3.5.1, item 3.5.1-51, addresses inaccessible concrete areas of Group 6 structures exposed to flowing water, which will be managed for increase in porosity and permeability, and for loss of strength due to leaching of calcium hydroxide and carbonation by the Structures Monitoring Program and the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The criteria in SRP-LR Section 3.5.2.2.2.3, item 3, states that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Group 6 concrete structures. The SRP-LR also states that further evaluation is required if leaching is observed in accessible areas that impact intended functions. The SRP-LR also states that further evaluation is required to determine if a plant-specific AMP is needed to manage the aging effect and that a plant-specific program is not required for the concrete exposed to flowing water if (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation or (2) evaluation determined that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on the intended function of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that BBS concrete structures are designed and constructed in accordance with ACI standards to produce concrete durable against leaching and carbonation. The applicant also stated that the effects of carbonation have not been observed on BBS concrete and that OE at BBS found that increase in porosity and permeability and loss of strength due to these mechanisms is not significant and is adequately managed by the enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, by performing periodic visual inspection of accessible and submerged concrete areas for these aging effects and by using conditions thereby found as an indicator to evaluate the condition of inaccessible areas. Also, the Structures Monitoring Program will examine exposed portions of below-grade concrete surfaces whenever excavated for any reason.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20, and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, is documented in SER Section 3.0.3.2.21. The staff noticed that the OE at BBS did not identify significant aging effects of degradation due to leaching and carbonation. Further, the staff noticed that enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, and the Structures Monitoring Program will be used to manage this aging effect for Group 6 concrete structures. The staff also noticed that the applicant cited generic Note E in the Table 2s for components associated with item 3.5.1-42 because the GALL Report recommends further evaluation to determine if a plant-specific program is needed to manage the aging effect or mechanism. In its review of components associated with item 3.5.1-51, the staff finds that the applicant has met the further evaluation criteria, and that the applicant's proposal to manage the effects of aging using the enhanced RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, and the Structures Monitoring Program is acceptable because these enhanced programs are consistent with the GALL-recommended programs capable of effectively monitoring and managing the aging effects, and because the applicant's review of OE did not indicate significant leaching or carbonation that would affect the intended function of the structure. Thus, an additional plant-specific program is not necessary.

Based on the programs identified, the staff determines that the applicant's programs meet the SRP-LR Section 3.5.2.2.2.3, item 3, criteria. For those items associated with LRA Section 3.5.2.2.2.3.3, the staff concludes that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions 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 3.5.2.2.2.4, associated with LRA Table 3.5.1, item 3.5.1-52, addresses cracking due to SCC and loss of material due to pitting and crevice corrosion in group 7 and 8 SS tank liners exposed to water – standing. The criteria in SRP-LR Section 3.5.2.2.2.4 state that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur for Group 7 and 8 stainless steel tank liners exposed to standing water. The SRP also states that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects. The applicant stated that this item is not applicable because the only Group 7 or 8 tanks present at BBS with an SS liner are the RWSTs. The applicant stated that for the purposes of aging management, these tank liners were evaluated within the SIS and assigned line items from GALL Report, Chapter V. The applicant stated that it will manage loss of material due to pitting and crevice corrosion by the Water Chemistry and One-Time Inspection Program. The normal operating environment for the RWSTs is limited to 100 °F in accordance with TS 3.5.4; therefore, cracking due to SCC is not an applicable aging effect for the RWST tank liners.

The staff noticed that LRA Table 3.5.1 item 3.5.1-52 is not applicable and that these components are evaluated with LRA Table 3.2.1 item 3.2.1-22, which references GALL Report items V.A.EP-41 and V.D1.EP-41 relative to the SIS. The staff noticed that GALL Report Chapter V Sections A and E1 do not address the aging effect of cracking due to SCC for SS tanks in a treated borated water environment with a temperature less than 140 °F (60 °C), only those with an environment above 140 °F. However, for the aging effect of loss of material due to pitting and crevice corrosion for SS tanks, the GALL Report recommends using Chapter XI.M2, Water Chemistry to manage aging. The staff noticed that the applicant is using Water Chemistry Program to manage loss of material due to pitting and crevice corrosion for SS tank liners, and finds it acceptable that the aging effect of cracking due to SCC is not applicable because the SS tank liners are limited to an environment (i.e., 100 °F < 140 °F) that will not cause them to be susceptible to this aging mechanism.

<u>Cumulative Fatigue Damage Due to Fatigue</u>. LRA Section 3.5.2.2.2.5, which is associated with LRA Table 3.5.1, item 3.5.1-53, addresses cumulative fatigue damage due to cyclic loading in component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue of Group B1.1 component supports is a TLAA, as defined in 10 CFR 54.3, and that Group B1.1 component supports are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Section 4.3.

The staff reviewed LRA Section 3.5.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.5, which states that fatigue of these structural 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). The staff reviewed the applicant's AMR line items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage for these structural components.

The applicant also stated that based on its reviews to identify TLAAs in the CLB, there are no other fatigue analyses for component support members for Groups B1.2 and B1.3. The staff reviewed the applicant's UFSAR and confirmed that the applicant's CLB does not contain fatigue analyses for component support members, anchor bolts, and welds for Groups B1.2 and B1.3 that are required to be identified as TLAAs in accordance with 10 CFR 54.21(c)(1). Therefore, the staff finds the applicant's claim acceptable.

The staff concludes that the applicant has met the SRP-LR Section 3.5.2.2.2.5 criteria. For those line items that apply to LRA Section 3.5.2.2.2.5, the staff determined that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these structural components.

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.

3.5.2.2.4 Operating Experience

SER Section 3.0.5, “Operating Experience for Aging Management Programs,” documents the staff’s evaluation of the applicant’s consideration of OE of AMPs.

3.5.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-18, 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 3.5.2-18, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR 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 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. The staff’s evaluation is discussed in the following sections.

3.5.2.3.1 Auxiliary Building—Summary of Aging Management Evaluation—LRA Table 3.5.2-1

Stainless Steel Elements (Accessible and Inaccessible Areas): Liner, Liner Anchors, and Integral Attachments Exposed to Waste Water. In LRA Table 3.5.2-1, the applicant stated that SS elements: liner, liner anchors, and integral attachments (accessible and inaccessible) exposed to waste water will be managed for loss of material by the Structures Monitoring Program. The AMR items cite generic Note G. The AMR items cite plant-specific note 7, which states that the Structures Monitoring Program is used to manage the aging effects applicable to this component type, material, and environment combination for the plates lining the sumps exposed to waste water.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to waste water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant’s proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S6.

The staff concludes for items in LRA Table 3.5.2-1 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.2 Circulating Water Pump House (Byron)—Summary of Aging Management Evaluation—LRA Table 3.5.2-2

Galvanized Steel Concrete Embedments and Components (Trash Rack Bars) Exposed to Raw Water. In LRA Table 3.5.2-2, the applicant stated that galvanized steel concrete embedments and components (trash rack bars) exposed to raw water will be managed for loss of material by the Structures Monitoring Program. The AMR items cite generic Note F and G, respectively.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that in GALL Report Section XI.C "Selected Definitions & Use of Terms for Describing and Standardizing Materials," the definition for galvanized steel states that in the presence of moisture, galvanized steel is classified under the category "steel." The staff also noticed that although not for this component, this material and environment combination is identified in the GALL Report, which indicates that steel components exposed to raw water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant has identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S6.

Stainless Steel Components (Anti-Vortex Components) Exposed to Raw Water. In LRA Table 3.5.2-2, the applicant stated that SS components (anti-vortex components) exposed to raw water will be managed for loss of material by the Structures Monitoring Program. The AMR item cites generic Note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to raw water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant has identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S6.

Reinforced Concrete Below-Grade Exterior (Inaccessible Areas) Exposed to Water-Flowing. In LRA Tables 3.5.2-2 and 3.5.2-11, the applicant stated that reinforced concrete below-grade exterior (inaccessible areas) exposed to water-flowing will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by the Structures Monitoring Program. The AMR items cite generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that reinforced concrete above- and below-grade (inaccessible areas) exposed to water-flowing is susceptible to increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide and carbonation, loss of material due to abrasion, or cavitation. The GALL Report recommends AMP XI.S7 to manage loss of material due to abrasion or cavitation. The staff also noticed that the GALL Report recommends further evaluation to determine if a plant-specific AMP is required to manage an increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation. However the applicant has identified cracking, loss of bond, and loss of material (spalling, scaling) as additional aging effects. The applicant addressed the GALL Report-identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-4, 3.5.2-5, 3.5.2-7, 3.5.2-8, 3.5.2-9, 3.5.2-10, 3.5.2-11, 3.5.2-12, 3.5.2-13, 3.5.2-14, 3.5.2-16 and 3.5.2-17.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage cracking, loss of bond, and loss of material using the Structures Monitoring Program acceptable because with implementation of program enhancements, (1) groundwater chemistry monitoring results exceeding the threshold criteria for pH, chlorides, and sulfates, will be evaluated to assess the impact on below-grade structures; (2) based on the groundwater chemistry monitoring results, a structure will be selected and inspected as the leading indicator for the condition of below-grade concrete exposed to groundwater; (3) an evaluation will be performed of the acceptability of inaccessible areas, when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas; and (4) examinations of representative samples of exposed portions of below-grade concrete will be performed, when excavated for any reason, consistent with the recommendations in GALL Report AMP XI.S6.

The staff concludes for items in LRA Table 3.5.2-2 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.3 Component Supports Commodity Group—Summary of Aging Management Evaluation—LRA Table 3.5.2-3

Carbon Steel Supports for ASME Class 1 Piping and Components (sliding surfaces—NSSS component supports) Exposed to Air with Borated Water Leakage. In LRA Table 3.5.2-3, the applicant stated that carbon steel supports for ASME Class 1 piping and components (sliding surfaces – NSSS component supports) exposed to air with borated water leakage will be managed for loss of mechanical function by the ASME Section XI, Subsection IWF program. The AMR item cites generic Note F. The AMR items cites plant-specific note 1, which states "the aging effects for carbon and stainless steel sliding surfaces in air with borated water leakage and treated borated water environments include loss of mechanical function due to corrosion, distortion, dirt, debris, overload, wear. The ASME Section XI, Subsection IWF program is used to manage the identified aging effect(s) applicable to these component types, materials, and environment combinations."

The staff noticed that this material and environment combination is identified in the GALL Report, which states that steel support members exposed to air with borated water leakage are susceptible to loss of material due to boric acid corrosion and recommends GALL Report AMP XI.M10 to manage the aging effect. The staff also noticed that steel support members exposed to air-indoor (uncontrolled) or air-outdoor are susceptible to loss of material due to general and pitting corrosion and recommends GALL Report AMP XI.S3 to manage the aging effect. However the applicant has identified loss of mechanical function as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.5.2-3.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWF program acceptable because the VT-3 visual examination method specified by the program will detect aging mechanisms such as corrosion, distortion, dirt, elastomer hardening, and clearances being less than the design requirements, which contribute to loss of mechanical function. If these aging mechanisms are identified, the program will implement appropriate corrective actions per the ASME Code Section IWF to ensure that carbon steel supports for ASME Class 1 piping and components (sliding surfaces – NSSS component supports) exposed to air with borated water leakage will continue to perform their function through the period of extended operation.

Carbon Steel Supports for Cable Trays, Conduit, HVAC, Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components (Sliding Support Bearings, Sliding Support Surfaces) Exposed to Air-Indoor Uncontrolled. In LRA Table 3.5.2-3, the applicant stated that carbon steel supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components (sliding support bearings; sliding support surfaces) exposed to air-indoor uncontrolled will be managed for loss of mechanical function by the Structures Monitoring Program. The AMR item cites generic note F. The AMR item cites plant-specific note 4, which states that the aging effects for carbon steel sliding surfaces in air-indoor and air with borated water leakage environments include loss of mechanical function due to corrosion, distortion, dirt, debris, overload, and wear. The Structures Monitoring Program is used to manage the identified aging effects applicable to these component types, materials, and environment combinations.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that steel support members, welds, bolted connections, and support anchorage to building structure exposed to air-indoor uncontrolled or air-outdoor are susceptible to loss of material due to general and pitting corrosion. The GALL Report recommends AMP XI.S6 to manage the aging effect. However the applicant has identified loss of mechanical function as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in other AMR items in LRA Table 3.5.2-3.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because in addition to monitoring accessible sliding surfaces for loss of material due to wear, corrosion, debris, dirt, or overload that could restrict or prevent sliding of surfaces, these components will also be monitored for loss of mechanical function through visual inspections at a frequency not to exceed 5 years, consistent with the recommendations in GALL Report AMP XI.S6.

<u>Carbon Steel Supports for Cable Trays, Conduit, HVAC, Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components (Sliding Support Bearings, Sliding Support Surfaces) Exposed to Air with Borated Water Leakage</u>. In LRA Table 3.5.2-3, the applicant stated that carbon steel supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components (sliding support bearings; sliding support surfaces) exposed to air with borated water leakage will be managed for loss of mechanical function by the Structures Monitoring Program. The AMR item cites generic Note F. The AMR item cites plant-specific Note 4, which states that the aging effects for carbon steel sliding surfaces in air-indoor and air with borated water leakage environments include loss of mechanical function due to corrosion, distortion, dirt, debris, overload, and wear. The Structures Monitoring Program is used to manage the identified aging effects applicable to these component types, materials, and environment combinations.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that steel support members, welds, bolted connections, and support anchorage to building structure exposed to air with borated water leakage are susceptible to loss of material due to boric acid corrosion and recommends GALL Report AMP XI.M10 to manage the aging effect. The staff also noticed that the applicant proposes to manage loss of material due to general and pitting corrosion using the Structures Monitoring Program for these components. However the applicant has identified loss of mechanical function as an additional aging effect. The applicant addressed the GALL Report-identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.5.2-3.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because in addition to monitoring accessible sliding surfaces for loss of material due to wear, corrosion, debris, dirt, or overload that could restrict or prevent sliding of surfaces, these components will also be monitored for loss of mechanical function through visual inspections at a frequency not to exceed 5 years, consistent with the recommendations in GALL Report AMP XI.S6.

<u>Stainless Steel Bolting for Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment (support members, welds, bolted connections, support anchorage to building structure)</u>. In LRA Table 3.5.2-3, revised by letter dated February 27, 2014, in response to RAI 3.5.2-1, the applicant stated that SS structural

bolting exposed to raw water will be managed for loss of material by the Structures Monitoring Program. The AMR item cites generic Note G.

The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which states that any structural bolting exposed to any environment is susceptible to loss of preload and recommends GALL Report AMP XI.S6 to manage the aging effect. However the applicant has identified loss of material as an additional aging effect. The applicant addressed the GALL Report-identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.5.2-7 and 3.5.2-14.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because, with implementation of the program enhancements, steel SCs, including structural bolting, will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in the GALL Report AMP XI.S6.

<u>Stainless Steel Supports for ASME Class MC components (Sliding Surfaces) Exposed to Treated Borated Water</u>. In LRA Table 3.5.2-3, the applicant stated that SS supports for ASME Class MC components (sliding surfaces) exposed to treated borated water will be managed for loss of mechanical function by the ASME Section XI, Subsection IWF program. The AMR item cites generic note F. The AMR items cites plant-specific note 1, which states "the aging effects for carbon and stainless steel sliding surfaces in air with borated water leakage and treated borated water environments include loss of mechanical function due to corrosion, distortion, dirt, debris, overload, wear. The ASME Section XI, Subsection IWF program is used to manage the identified aging effect(s) applicable to these component types, materials, and environment combinations."

The staff noticed that this material and environment combination is identified in the GALL Report, which states that SS exposed to treated borated water is susceptible to loss of material due to pitting and crevice corrosion. The GALL Report recommends AMP XI.M2 and AMP XI.S3 to manage the aging effect. However the applicant has identified loss of mechanical function as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.5.2-3.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's proposal to manage the effects of aging using the ASME Section XI, Subsection IWF program acceptable because the VT-3 visual examination method specified by the program will detect aging mechanisms such as corrosion, distortion, dirt, elastomer hardening, and clearances being less than the design requirements, which contribute to loss of mechanical function. If these aging mechanisms are identified, the program will implement appropriate corrective actions per the ASME Code Section IWF to ensure that SS supports for ASME Class MC components (sliding surfaces) exposed to treated borated water will continue to be able to perform their function through the period of extended operation.

<u>Carbon Steel Components Exposed to Air with Borated Water Leakage</u>. The staff's evaluation for carbon steel components exposed to air with borated water leakage, for which the applicant

did not include AMR items for loss of material due to general, pitting, and crevice corrosion, is documented in SER Section 3.2.2.3.1.

The staff concludes for items in LRA Table 3.5.2-3 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.4 Containment Structure—Summary of Aging Management Evaluation—LRA Table 3.5.2-4

Miscellaneous Stainless Steel (Catwalks, Stairs, Handrails, Ladders, Vents and Louvers, Platforms, etc.) Exposed to Treated Borated Water. In LRA Table 3.5.2-4, the applicant stated that miscellaneous SS (catwalks, stairs, handrails, ladders, vents and louvers, platforms, etc.) exposed to treated borated water will be managed for loss of material and cracking by the Structures Monitoring Program. The AMR items cite generic note F. The AMR item cites plant-specific note 7, which states that the Structures Monitoring Program is used to manage the aging effects applicable to this component type, material, and environment combination at the refueling cavity.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to treated borated water are susceptible to loss of material. The staff also noticed that the GALL Report identifies cracking due to SCC as a credible aging effect for SS exposed to treated borated water greater than 140 °F (greater than 60 °C); although the applicant is proposing to manage cracking, LRA Table 3.5.1-78 states that “cracking is not an expected aging effect since the normal spent fuel pool and refueling cavity temperatures are less than 140 °F.” Additionally, the applicant is proposing to use the Water Chemistry Program to manage loss of material and cracking of the SS refueling cavity liner, which is the area in which these miscellaneous steel components are located, by monitoring concentrations of corrosive impurities listed in the EPRI water chemistry guidelines to mitigate loss of material due to corrosion and cracking due to SCC. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant has identified all credible aging effects for this material and environment combination.

The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant’s proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S6, and because periodic monitoring of the refueling water (treated borated water) through the Water Chemistry Program is an adequate mitigative approach to minimizing loss of material and cracking.

Stainless Steel Penetration Sleeves (Guard Pipe for Recirculation Sump Effluent Pipe) Exposed to Waste Water. In LRA Table 3.5.2-4, the applicant stated that SS penetration sleeves (guard pipe for recirculation sump effluent pipe) exposed to waste water will be managed for loss of material by the Structures Monitoring Program. The AMR item cites generic note G. The AMR item cites plant-specific note 11, which states that the Structures Monitoring Program is used to manage the aging effects applicable to this component type, material, and environment combination for the sump liners.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that the applicant also proposes to use the 10 CFR Part 50, Appendix J Program to manage loss of material for this component, material, and environment combination in LRA Table 3.5.2-4. Based on its review of items in the GALL Report for the same material and environment combination, which indicates that SS piping, piping components, and piping elements exposed to waste water is susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program and 10 CFR Part 50, Appendix J Program is documented in SER Sections 3.0.3.2.20 and 3.0.3.1.14, respectively. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S6.

<u>Stainless Steel Elements: Liner, Liner Anchors, Integral Attachments (Sumps—Accessible Areas) Exposed to Waste Water</u>. In LRA Table 3.5.2-4, the applicant stated that SS elements: liner, liner anchors, and integral attachments (sumps-accessible areas) exposed to waste water will be managed for loss of material by the Structures Monitoring Program. The AMR item cites generic Note G. The AMR item cites plant-specific note 11, which states that the Structures Monitoring Program is used to manage the aging effects applicable to this component type, material, and environment combination for the sump liners.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements; tanks exposed to waste water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant has identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in the GALL Report.

<u>Fiberglass Precast Panel (Containment Access Facility Hallway)—(Byron Only) Exposed to Air-Outdoor</u>. In LRA Table 3.5.2-4, revised by letter dated December 19, 2013, in response to RAI 2.1-3, the applicant stated that fiberglass precast panel exposed to air-outdoor will be managed for change in material properties by the Structures Monitoring Program. The AMR item cites generic Note J. The AMR item cites plant-specific Note 16, which states, "this material has a potential to experience a change in material properties in an air-outdoor environment. The Structures Monitoring Program (B.2.1.34) is credited to manage the aging effects applicable to this component type, material, and environment combination."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant are appropriate for the material and environment combination. In its review of Fiberglass Pipe Design—Manual of Water Supply Practices, M45 (2nd Edition), American Water Works Association 2005, for weather resistance of fiberglass pipes, the staff noticed that "[m]ost thermosetting resin systems used to fabricate fiberglass pipe are subject to some degradation from ultraviolet (UV) light. This degradation is almost entirely a surface phenomenon." Based on its review of Fiberglass Pipe Design – Manual of Water Supply Practices, the staff noticed that fiberglass would exhibit surface conditions that may be indicative of a change in material properties; and therefore, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Structure's Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because (1) by letter dated December 19, 2013, in response to RAI 2.1-3, the program was revised to include the CAF hallway within the "scope of program" and specify that fiberglass will be monitored for change in material properties, and (2) periodic visual inspections are capable of detecting surface conditions which may be indicative of a change in material properties.

<u>Carbon Steel Penetration Sleeves (Guard Pipe for Recirculation Sump Effluent Pipe) Exposed to Condensation</u>. In LRA Table 3.5.2-4, the applicant stated that carbon steel penetration sleeves (guard pipe for recirculation sump effluent pipe) exposed to condensation will be managed for loss of material by the 10 CFR Part 50, Appendix J Program. The AMR items cite generic Note G. The AMR items also cite plant-specific note 10, which states that the 10 CFR Part 50, Appendix J Program will be used to manage this aging effect in the gap between the guard pipe and the recirculation sump effluent pipe.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that carbon steel piping, piping components, and piping elements exposed to condensation are susceptible to loss of material. However, the staff also noticed that GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J," states that type B (local leakage rate tests – LLRTs) tests are intended to detect local leaks and to measure leakage across each pressure-containing or leakage-limiting boundary of containment penetration. It also states that:

> while the calculation of leakage rates and satisfactory performance of containment leakage rate testing demonstrates the leak-tightness and structural integrity of the containment, it does not by itself provide information that would indicate that aging degradation has initiated…This would be achieved with the additional implementation of an acceptable containment inservice inspection program…

It is not clear if the 10 CFR Part 50, Appendix J Program alone, will identify loss of material for these components, when the primary role of the program for these penetrations is to perform periodic LLRTs. Therefore, by letter dated April 7, 2014, the staff issued RAI 3.5.2-5 requesting that the applicant clarify if visual inspections are performed as part of the 10 CFR Part 50, Appendix J Program or explain how LLRTs will detect loss of material, prior to a loss of intended function.

In its response dated May 6, 2014, the applicant stated that:

> [v]isual inspections are not performed as part of the 10 CFR Part 50, Appendix J (B.2.1.32) aging management program…The condensation environment represents the environment inside the annular space, which is inaccessible…Testing performed under the 10 CFR Part 50, Appendix J (B.2.1.32) aging management program will demonstrate the leak-tightness and structural integrity of these components. These inaccessible component areas are exempt from examination in accordance with the ASME Section XI, Subsection IWE, paragraph IWE-1220.

The staff noticed that the applicant revised each of the plant-specific notes for these components to clarify that the components are inaccessible and exempt from examination in accordance with ASME Code Section XI, Subsection IWE, paragraph IWE-1220. The staff finds the applicant's response acceptable because it clarified that the components are inaccessible and exempt from visual examination in accordance with ASME Code Section XI, Subsection IWE. Although testing performed under the 10 CFR Part 50, Appendix J Program may not directly detect a loss of material, it will demonstrate the leak-tightness and structural integrity of these components. The staff's concern described in RAI 3.5.2-5 is resolved. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's 10 CFR Part 50, Appendix J Program is documented in SER Section 3.0.3.1.14. The staff finds the applicant's proposal to manage the effects of aging using the 10 CFR Part 50, Appendix J Program acceptable because the testing done under the 10 CFR Part 50, Appendix J Program will demonstrate the leak-tightness and structural integrity of these components.

<u>Stainless Steel Penetration Sleeves (Guard Pipe for Recirculation Sump Effluent Pipe and Guard Pipe for Fuel Transfer Tube) Exposed to Condensation</u>. In LRA Table 3.5.2-4, the applicant stated that SS penetration sleeves (guard pipe for recirculation sump effluent pipe and guard pipe for fuel transfer tube) exposed to condensation will be managed for loss of material and cracking by the 10 CFR Part 50, Appendix J Program. The AMR items cite generic Note G. The AMR items associated with the guard pipe for the recirculation sump effluent pipe also cite plant-specific note 10, which states that the 10 CFR Part 50, Appendix J Program will be used to manage this aging effect in the gap between the guard pipe and the recirculation sump effluent pipe. The AMR items associated with the guard pipe for the fuel transfer tube also cite plant-specific note 8, which states that the 10 CFR Part 50, Appendix J Program will be used to manage this aging effect in the gap between the guard pipe and the fuel transfer tube.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, the material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to condensation are susceptible to loss of material. The staff also noticed that the GALL Report identifies cracking due to SCC as a credible aging effect for SS exposed to treated borated water greater than 140 °F (greater than 60 °C). The staff further noticed, that in response to RAI 3.5.2-5, the applicant clarified that the gap between the guard pipe and recirculation sump effluent pipe, and the gap between the guard pipe and fuel transfer tube, are inaccessible annular spaces and are exempt from examination in accordance with ASME Section XI, Subsection IWE. The staff further noticed that GALL Report AMP XI.S1 states that where feasible, Appendix J tests may be performed in lieu of surface examinations for SS penetration sleeves. The applicant, as noted in its response to RAI 3.5.2-5, will employ its 10 CFR Part 50 Appendix J Program to evaluate the leak tightness and structural integrity of the referenced SS penetration sleeves for loss of material and cracking._ The staff's evaluation of RAI 3.5.2-5 is documented in SER Section 3.5.2.3.4 above. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination

The staff's evaluation of the applicant's 10 CFR Part 50, Appendix J Program is documented in SER Section 3.0.3.1.14. The staff finds the applicant's proposal to manage the effects of aging using the 10 CFR Part 50, Appendix J Program, acceptable because the testing done under the 10 CFR Part 50, Appendix J Program will demonstrate the leak-tightness and structural integrity of these components.

<u>Stainless Steel Penetration Sleeves (Guard Pipe for Recirculation Sump Effluent Pipe) Exposed to Waste Water</u>. In LRA Table 3.5.2-4, the applicant stated that SS penetration sleeves (guard pipe for recirculation sump effluent pipe) exposed to waste water will be managed for loss of material by the 10 CFR Part 50, Appendix J AMP. The AMR item cites generic Note G. The AMR item also cite plant-specific Note 10, which states that the 10 CFR Part 50, Appendix J AMP will be used to manage this aging effect in the gap between the guard pipe and the recirculation sump effluent pipe.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to wastewater are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's 10 CFR Part 50, Appendix J Program is documented in SER Section 3.0.3.1.14. The staff finds the applicant's proposal to manage the effects of aging using the 10 CFR Part 50, Appendix J Program acceptable because the testing done under the 10 CFR Part 50, Appendix J Program will demonstrate the leak-tightness and structural integrity of these components.

The staff concludes for items in LRA Table 3.5.2-4 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.5 Deep Well Enclosures (Byron)—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 deep well enclosures (Byron only) system component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the deep well enclosures (Byron only) system component groups are consistent with the GALL Report.

3.5.2.3.6 Essential Service Cooling Pond (Braidwood)—Summary of Aging Management Evaluation—LRA Table 3.5.2-6

Soil, Rip-Rap, Sand, and Gravel Earthen Water-Control Structures Exposed to Air-Outdoor. In LRA Table 3.5.2-6, the applicant stated that soil, rip-rap, sand, and gravel earthen water-control structures (spillway and dike system) exposed to air-outdoor will be managed for loss of material or loss of form by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR items cite generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. In its review of GALL Report Chapter IX.E, "Selected use of Terms for Describing and Standardizing Aging Effects," the staff noticed that the GALL Report states that loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage in earthen water-control structures. Additionally, based on its review of "Fundamentals of Soil Behavior" by Mitchell and Soga, dated 2005, which states "…wind…and gravity continually erode and transport soil and rock debris away from the zone of weathering," the staff finds that loss of material and loss of form is an appropriate aging effect and that the applicant has identified all credible aging effects for this component, material, and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because, consistent with the recommendations in GALL Report AMP XI.S7, the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program monitors and inspects earthen embankment structures for parameters such as settlement, depressions, sinkholes, slope stability, (e.g., irregularities in alignment and variances from originally constructed slopes), seepage, and degradation of slope protection features, which would indicate a loss of material or loss of form.

The staff concludes for items in LRA Table 3.5.2-6 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.7 Essential Service Water Cooling Towers (Byron)—Summary of Aging Management Evaluation—LRA Table 3.5.2-7

Stainless Steel Hatches/Plugs Exposed to Raw Water. In LRA Table 3.5.2-7, the applicant stated that SS hatches/plugs exposed to raw water will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to raw water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because, with implementation of the program enhancements, the AMP will require periodic visual inspections of steel components subject to RG 1.127 for loss of material, at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S7.

Stainless Steel Hatches/Plugs Exposed to Air-Outdoor. In LRA Table 3.5.2-7, the applicant stated that SS hatches/plugs exposed to air-outdoor will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to air-outdoor are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because, with implementation of the program enhancements, the AMP will require periodic visual inspections of steel components subject to RG 1.127 for loss of material, at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S7.

Galvanized Steel Concrete Embedments Exposed to Raw Water. In LRA Tables 3.5.2-7, 3.5.2-9, and 3.5.2-14, the applicant stated that galvanized steel concrete embedments exposed to raw water will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that in GALL Report Section XI.C, "Selected Definitions & Use of Terms for Describing and Standardizing Materials, the definition for galvanized steel states that in the presence of moisture, galvanized steel is classified under the category "steel." The staff also noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that steel components exposed to raw water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because, with implementation of the program enhancements, the AMP will require periodic visual inspections of steel components subject to RG 1.127 for loss of material, at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S7.

Stainless Steel Structural Bolting Exposed to Raw Water. In LRA Table 3.5.2-7 and 3.5.2-14, the applicant stated that SS structural bolting exposed to raw water will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note G.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that any structural bolting exposed to any environment is susceptible to loss of preload. The GALL Report recommends AMP XI.S6 to manage the aging effect. However, the applicant has identified loss of material as an additional aging effect. The applicant addressed the GALL Report-identified aging effects for this component, material and environment combination in other AMR items in LRA Tables 3.5.2-7 and 3.5.2-14.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable, because with implementation of the program enhancements, the AMP will (1) provide guidance for specification of structural bolting material, and lubricant to prevent or mitigate degradation and failure of structural bolting, (2) provide storage requirements for structural bolting to include recommendations of the RCSC Specification for Structural Joints Using High-Strength Bolts, (3) clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluation, and (4) require that steel components subject to RG 1.127 be inspected for loss of material.

Above-Grade Exterior Reinforced Concrete (Accessible and Inaccessible Areas) Exposed to Water-Flowing. In LRA Table 3.5.2-7, the applicant stated that above-grade exterior reinforced concrete (accessible and inaccessible areas) exposed to water-flowing will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR items cite generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report for below-grade reinforced concrete, which states that exterior above- and below-grade concrete exposed to water-flowing is susceptible to (1) loss of material due to abrasion and cavitation, and (2) increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation. The GALL Report recommends AMP XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corps of Engineers dam inspections and maintenance programs to manage these aging effects. However, the applicant has identified cracking, loss of bond, and loss of material (spalling, scaling) as additional aging effects. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.5.2-7, 3.5.2-9, and 3.5.2-14.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage cracking, loss of bond, and loss of material (spalling, scaling) using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because, with implementation of the program enhancements, the AMP will (1) include all aging effects addressed by ACI 349.3R in procedures and require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R, and (2) require the evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, which is consistent with the recommendations in GALL Report AMP XI.S7.

<u>Below-Grade Exterior Reinforced Concrete (Inaccessible Areas) Exposed to Water-Flowing</u>. In LRA Tables 3.5.2-7, 3.5.2-9, and 3.5.2-14, the applicant stated that below-grade exterior reinforced concrete (inaccessible areas) exposed to water-flowing will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR items cite generic Note H.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that exterior above- and below-grade concrete exposed to water-flowing is susceptible to (1) loss of material due to abrasion and cavitation, and (2) increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation. The GALL Report recommends AMP XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs to manage loss of material due to abrasion. The GALL Report recommends further evaluation to determine if a plant-specific AMP is needed to manage increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide. However, the applicant has identified cracking, loss of bond, and loss of material as additional aging effects. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Tables 3.5.2-7, 3.5.2-9, and 3.5.2-14.

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 3.0.3.2.21. In addition, the staff's review of the applicant's evaluation of the aging effect increase in porosity and permeability, and the evaluation of loss of strength due to leaching of calcium hydroxide is documented in SER Section 3.5.2.2.2. The staff finds the applicant's proposal to manage cracking, loss of bond, and loss of material (spalling, scaling) using the RG 1.127 acceptable because with implementation of the program enhancements, the AMP will (1) require inspectors work under the direction of a qualified engineer for submerged concrete inspections, (2) require examination of representative samples of the exposed portions of the below-grade concrete, when excavated for any reason, (3) monitor raw water and groundwater chemistry at least once every 5 years for pH, chlorides, and sulfates and verify that it remains nonaggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete, and (4) require visual inspections of submerged concrete structural components by dewatering a structure or by a diver if the structure is not dewatered at least once every 5 years, which is consistent with the recommendations in GALL Report AMP XI.S7.

Ceramic Tile Cooling Tower Fill Exposed to Air-Outdoor. In LRA Table 3.5.2-7, the applicant stated that ceramic tile cooling tower fill exposed to air-outdoor will be managed for loss of material (spalling, scaling) by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note J. The AMR item cites plant-specific note 6, which states that the ceramic tile, a vitrified clay fill, is susceptible to loss of material (spalling, scaling) and cracking due to freeze-thaw.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the ASM Handbook, Volume 20 - Materials Selection and Design, 1997, which states that "a greater quantity of pores [in structural clay products], as defined by the weight percent of water absorption, decreases strength, resistance to cyclic freezing of water-saturated material, insulating value, and corrosion resistance of product," the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the program enhancements, the AMP will clarify that parameters to be monitored and inspected at the essential service water cooling towers include visual inspection for loss of material and reduction of heat transfer for the cooling tower fill.

Ceramic Tile Cooling Tower Fill Exposed to Water-Flowing. In LRA Table 3.5.2-7, the applicant stated that ceramic tile cooling tower fill exposed to water-flowing will be managed for reduction of heat transfer by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note J. The AMR item cites plant-specific note 7, which states that the ceramic tile, a vitrified clay fill, is susceptible to reduction of heat transfer due to fouling.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of ASM Handbook, Volume 20 - Materials Selection and Design, 1997, which states that "a greater quantity of pores [in structural clay products], as defined by the weight percent of water absorption, decreases strength, resistance to cyclic freezing of water-saturated material, insulating value, and corrosion resistance of product," the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the enhancements, the AMP will clarify that parameters to be monitored and inspected at the essential service water cooling towers include visual inspection for loss of material and reduction of heat transfer for the cooling tower fill.

PVC Louvers (Drift Eliminators) Exposed to Air-Outdoor. In LRA Table 3.5.2-7, the applicant stated that PVC louvers (drift eliminators) exposed to air-outdoor will be managed for change in material properties by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note J. The AMR item cites plant-specific note 8, which states that "this material has a potential to experience a change in material properties…Although exposed to outdoor air, the PVC louvers (drift eliminators) are internal to the cooling towers and sheltered from direct UV exposure…Nonetheless, the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program is credited for ensuring the absence of any aging effects."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed that, although not for an air-outdoor environment, PVC exposed to air-indoor, uncontrolled or condensation is evaluated in the GALL Report, which indicates that there are no aging effects for this material and environment combination. Based on its review of PVC exposed to an air-outdoor environment, the staff found that in the presence of direct UV radiation, a change in material properties could occur. The staff noticed in its review of Uni-Bell PVC Pipe Association, Handbook of PVC Pipe Design and Construction (5th Edition,) 2013, "that exposure to UV radiation results in a changing in the pipe's surface color and a slight reduction in impact strength." Although these components are not directly exposed to UV radiation, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the program enhancements, the AMP will clarify that parameters to be monitored and inspected at the essential service water cooling towers include visual inspection and physical manipulation for change in material properties associated with the PVC drift eliminators.

PVC Louvers (Drift Eliminators) Exposed to Raw Water. In LRA Table 3.5.2-7, the applicant stated that PVC louvers (drift eliminators) exposed to raw water will be managed for change in material properties by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note J. The AMR item cites plant-specific note 8, which states that "this material has a potential to experience a change in material properties…Although exposed to outdoor air, the PVC louvers (drift eliminators) are internal to the cooling towers and sheltered from direct UV exposure…Nonetheless, the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program is credited for ensuring the absence of any aging effects."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noticed, although not for a raw water environment, PVC exposed to air-indoor, uncontrolled or condensation is evaluated in the GALL Report, which indicates that there are no aging effects for this material and environment combination. PVC is a material known to have a high resistance to corrosion, permeation, and chemical attack. The staff noticed that the PVC Pipe – Design and Installation – Manual of Water Supply Practices, M23, American Water Works Association, Second Edition, 2002, states that "PVC is nearly totally resistant to biological attack. Biological attack can be described as degradation or deterioration caused by the action of living." The staff also considered that, for PVC pipe, direct exposure to UV radiation could result in the aging effect of change in material properties; however, as noted by the applicant, these components are internal to the structure and sheltered from direct UV exposure. Overall, the applicant identified change in material properties as a potential aging effect, and the staff finds the applicant's proposal to manage this aging effect acceptable.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the program enhancements, the AMP will clarify that parameters to be monitored and inspected at the essential service water cooling towers include visual inspection and physical manipulation for change in material properties associated with the PVC drift eliminators.

<u>Fiberglass Support Beams for Drift Eliminators Exposed to Air-Outdoor</u>. In LRA Table 3.5.2-7, the applicant stated that fiberglass support members, welds, bolted connections, and support anchorage to building structure (support beams for drift eliminators) exposed to air-outdoor will be managed for change in material properties by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note J. The AMR item cites plant-specific Note 9, which states that "this material has a potential to experience a change in material properties…Although exposed to outdoor air, the fiberglass components are internal to the cooling towers and sheltered from direct UV exposure…Nonetheless, the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program is credited for ensuring the absence of any aging effects."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff finds the applicant's proposal acceptable 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, Plastic Piping Institute, Recommended Design Factors and Design Coefficients for Thermoplastic Pressure Pipe, TR-9/2002, October 2002). In its review, the staff noticed that fiberglass reinforced plastic piping and piping components, in the absence of specific environmental stressors such as UV radiation, high radiation, or ozone concentrations, will not exhibit aging effects of concern during the period of extended operation. Overall, the applicant identified change in material properties as a potential aging effect, and the staff finds the applicant's proposal to manage this aging effect acceptable.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the program enhancements, the AMP will state that parameters to be monitored and inspected at the essential service water cooling towers include visual inspection and physical manipulation for change in material properties associated with the fiberglass support beams for the drift eliminators.

<u>Fiberglass Support Beams for Drift Eliminators Exposed to Raw Water</u>. In LRA Table 3.5.2-7, the applicant stated that fiberglass support members, welds, bolted connections, and support

anchorage to building structure (support beams for drift eliminators) exposed to air-outdoor will be managed for change in material properties by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic note J. The AMR item cites plant-specific Note 9, which states that "this material has a potential to experience a change in material properties…Although exposed to outdoor air, the fiberglass components are internal to the cooling towers and sheltered from direct UV exposure…Nonetheless, the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program is credited for ensuring the absence of any aging effects."

The staff noticed that this material and environment combination is identified in the GALL Report, which states that fiberglass piping, piping components, and piping elements exposed to raw water are susceptible to cracking, blistering, and change in color due to water absorption. However the applicant identified change in material properties as an additional aging effect.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the program enhancements, the AMP will clarify that parameters to be monitored and inspected at the essential service water cooling towers include visual inspection and physical manipulation for change in material properties associated with the fiberglass support beams for the drift eliminators, and the periodic visual inspections performed under the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program would identify cracking, blistering, and change in color.

The staff concludes for items in LRA Table 3.5.2-7 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.8 Fuel Handling Building—Summary of Aging Management Evaluation—LRA Table 3.5.2-8

<u>Stainless Steel Concrete Embedments (Scuppers), Miscellaneous Stainless Steel (Catwalks, Stairs, Handrails, Ladders, Vents and Louvers, Platforms, etc.), and Stainless Steel Spent Fuel Pool Gates Exposed to Treated Borated Water</u>. In LRA Table 3.5.2-8, the applicant stated that SS concrete embedments (scuppers), miscellaneous SS (catwalks, stairs, handrails, ladders, vents and louvers, platforms, etc.), and SS SFP gates exposed to treated borated water will be managed for loss of material by the Structures Monitoring Program. The AMR items cite generic Note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, piping elements, and tanks exposed to waste water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant has identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S6.

<u>Stainless Steel Penetration Bellows and Penetration Sleeves (Fuel Transfer Tube) Exposed to Condensation</u>. In LRA Table 3.5.2-8, the applicant stated that SS penetration bellows and penetration sleeves (fuel transfer tube) exposed to condensation will be managed for loss of material by the 10 CFR Part 50, Appendix J Program. The AMR items cite generic Note G. The AMR items also cite plant-specific Note 5, which states that, "the fuel transfer tube penetration sleeve and penetration bellows inside the Fuel Handling Building are tested concurrently with the fuel transfer tube penetration sleeve and penetration bellows inside the Containment Structure…."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which indicates that SS piping, piping components, and piping elements exposed to condensation are susceptible to loss of material. The staff also noticed, that in response to RAI 3.5.2-5, the applicant clarified that the space between the fuel transfer tube penetration sleeve and penetration bellows, and the fuel transfer tube, are inaccessible annular spaces and are exempt from examination in accordance with ASME Code Section XI, Subsection IWE. The staff's evaluation of RAI 3.5.2-5 is documented in SER Section 3.5.2.3.4 above. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant has identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's 10 CFR Part 50, Appendix J Program is documented in SER Section 3.0.3.1.14. The staff finds the applicant's proposal to manage the effects of aging using the 10 CFR Part 50, Appendix J Program acceptable because the testing done under the 10 CFR Part 50, Appendix J Program will demonstrate the leak-tightness and structural integrity of these components.

<u>Stainless Steel Elements: Liner, Liner Anchors, Integral Attachments (accessible areas and inaccessible areas) Exposed to Treated Borated Water</u>. In LRA Table 3.5.2-8, the applicant stated that there is a TLAA for SS elements: liner, liner anchors, integral attachments (accessible areas) exposed to treated borated water, and SS elements: liner, liner anchors, integral attachments (inaccessible areas) exposed to treated borated water, which cite generic Note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3, Metal Fatigue, for this component and material. The staff's evaluation of the TLAA for the SS SFP liner is documented in SER Section 4.3.9.

The staff concludes for items in LRA Table 3.5.2-8 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.9 Lake Screen Structures (Braidwood)—Summary of Aging Management Evaluation—LRA Table 3.5.2-9

Galvanized Steel Concrete Embedments Exposed to Raw Water. The staff's evaluation for galvanized steel concrete embedments exposed to raw water, which will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and are associated with generic Note F, is documented in SER Section 3.5.2.3.7.

Below-Grade Exterior Reinforced Concrete (Inaccessible Areas) Exposed to Water-Flowing. The staff's evaluation for below-grade exterior reinforced concrete (inaccessible areas) exposed to water-flowing, which will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and are associated with generic Note H, is documented in SER Section 3.5.2.3.7.

The staff concludes for items in LRA Table 3.5.2-9 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.10 Main Steam & Auxiliary Feedwater Tunnels and Isolation Valve Rooms—Summary of Aging Management Evaluation—LRA Table 3.5.2-10

Polymer Blowout Panels Exposed to Air-Indoor, Uncontrolled or Air-Outdoor. In LRA Table 3.5.2-10, the applicant stated that polymer blowout panels exposed to air- indoor, uncontrolled, or air-outdoor will be managed for change in material properties by the Structures Monitoring Program. The AMR items cite generic Note J. The AMR items cite plant-specific note 1, which states that the blowout panels are constructed of extruded polystyrene.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. In its review of extruded polystyrene exposed to an air-indoor or air-outdoor environment, the staff noticed that at high temperatures this material begins to degrade. The staff also noticed that unlike GALL Report AMPs XI.M36, "External Surfaces Monitoring of Mechanical Components," and XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," GALL Report AMP XI.S6, "Structures Monitoring" does not include examples of inspection parameters for polymeric components. Sufficient information was not provided to conclude that the visual inspections performed under the Structures Monitoring Program would identify a change in material properties, prior to a loss of intended function. Therefore, by letter dated May 21, 2014, the staff issued RAI 3.5.2.10-1 requesting that the applicant state how the visual inspections performed under the Structures Monitoring Program would identify a change in material properties for these components, and provide the acceptance criteria by which they would be evaluated.

In its response dated June 16, 2014, the applicant stated that visual inspections will identify a change in material properties of the polystyrene blowout panels through observation of parameters such as discoloration, cracking, crazing, and loss of material. The applicant also stated that "[a]cceptance criteria for inspection of polymeric structural components will consist of no observations of discoloration, cracking, crazing, or loss of material indicative of a change in material properties that could result in a loss of component intended function." The applicant further stated that physical manipulation of the polystyrene blowout panels is not required to identify a change in material properties because the panels are not flexible. In its response the applicant revised LRA Sections A.1.2.34, B.2.1.34, and LRA Table A.5 to incorporate a new enhancement (Enhancement 17) to the Structures Monitoring Program, clarifying that visual inspections of polymeric components will be performed for observations of material discoloration, cracking, crazing, and loss of material, which would be indicative of a change in material properties. The staff's evaluation of the applicant's enhancement to the Structures Monitoring Program is documented in SER Section 3.0.3.2.20.

The staff finds the applicant's response acceptable because:

- The applicant will enhance the Structures Monitoring Program to perform visual inspections of polymeric components for signs of discoloration, cracking, crazing and loss of material, which may be indicative of a change in material properties.
- The acceptance criteria include no signs of discoloration, cracking, crazing, or loss of material indicative of change in material properties that may result in loss of the polystyrene blowout panel intended function.

The staff's concern described in RAI 3.5.2.10-1 is resolved. The staff finds the applicant's proposal to manage a change in material properties of polymer blowout panels acceptable.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because periodic visual inspections of the polymeric components will identify material discoloration, cracking, crazing, and loss of material, which may be indicative of a change in material properties, and the applicant's proposal is consistent with the recommendations in GALL Report AMPs XI.M36 and AMP XI.M38, for managing aging effects in non-flexible polymers.

The staff concludes for items in LRA Table 3.5.2-10 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.11 Natural Draft Cooling Towers (Byron)—Summary of Aging Management Evaluation—LRA Table 3.5.2-11

<u>Reinforced Concrete Above- and Below-Grade (Inaccessible Areas) Exposed to Water-Flowing</u>. In LRA Table 3.5.2-11, the applicant stated that reinforced concrete above- and below-grade (inaccessible areas) exposed to water-flowing will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by the Structures Monitoring Program. The AMR items cite generic Note H. The AMR items cite plant-specific Note 1, which states that the reinforced concrete in a water flowing environment is also susceptible to cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded or reinforcing steel.

The staff noticed that this material and environment combination is identified in the GALL Report, which states that reinforced concrete above- and below-grade (inaccessible areas) exposed to water-flowing is susceptible to increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide and carbonation, loss of material due to abrasion, or cavitation. The GALL Report recommends AMP XI.S7 to manage loss of material due to abrasion; cavitation. The staff also noticed that the GALL Report recommends further evaluation to determine if a plant-specific AMP is required to manage an increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation.

However, the applicant has identified cracking, loss of bond, and loss of material (spalling, scaling) as additional aging effects. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in other AMR items in LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-4, 3.5.2-5, 3.5.2-7, 3.5.2-8, 3.5.2-9, 3.5.2-10, 3.5.2-11, 3.5.2-12, 3.5.2-13, 3.5.2-14, 3.5.2-16 and 3.5.2-17.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage cracking, loss of bond, and loss of material using the Structures Monitoring Program acceptable because with implementation of program enhancements, (1) visual inspections by qualified personal will be performed at a frequency not to exceed 5 years using the guidance of ACI 349.3R, (2) groundwater chemistry monitoring results exceeding the threshold criteria for pH, chlorides, and sulfates, will be evaluated to assess the impact on below-grade structures, (3) based on the groundwater chemistry monitoring results, a structure will be selected and inspected every 5 years as the leading indicator for the condition of below-grade concrete exposed to groundwater, (4) an evaluation will be performed of the acceptability of inaccessible areas, when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas, and (5) examinations of representative samples of exposed portions of below-grade concrete will be performed, when excavated for any reason, which is consistent with the recommendations in GALL Report AMP XI.S6.

The staff concludes for items in LRA Table 3.5.2-11 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.12 RWST Foundation and Tunnel—Summary of Aging Management Evaluation—LRA Table 3.5.2-12

<u>Miscellaneous Stainless Steel (catwalks, stairs, handrails, ladders, vents and louvers, platforms, etc.) Exposed to Treated Borated Water</u>. The staff's evaluation for miscellaneous SS (catwalks, stairs, handrails, ladders, vents and louvers, platforms, etc.) exposed to treated borated water, which will be managed for loss of material by the Structures Monitoring Program and is associated with generic Note F, is documented in SER Section 3.5.2.3.8.

The staff concludes for items in LRA Table 3.5.2-12 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.13 Radwaste and Service Building Complex—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 radwaste and service building complex component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the radwaste and service building complex component groups are consistent with the GALL Report.

3.5.2.3.14 River Screen House (Byron)—Summary of Aging Management Evaluation—LRA Table 3.5.2-14

Polymer Windows Exposed to Air-Indoor (Uncontrolled) and Air-Outdoor. In LRA Tables 3.5.2-14 and 3.5.2-17, the applicant stated that polymer windows exposed to air-indoor and air-outdoor will be managed for change in material properties by the Structures Monitoring Program. The AMR items cite generic Note J. The AMR items cite plant-specific notes 7 and 3, respectively, which indicate that the river screen house and turbine building window panes are Plexiglas (polymer material), and that the Structures Monitoring Program will be used to manage the changes in material properties (cracking or degradation).

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the Handbook of Material Weathering (2nd Edition), G. Wypych (1995), which indicates that polymethyl methacrylate, (e.g., Plexiglas) is UV-durable, the staff notes that "depolymerization occurs during weathering but such changes are mainly restricted to the specimen surface." Based on its review of the Handbook of Material Weathering, the staff noted that Plexiglas would exhibit surface conditions that may be indicative of a change in material properties and therefore, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because periodic visual inspections are capable of detecting cracking or degradation of the Plexiglas window panes, which may be indicative of a change in material properties.

Stainless Steel Concrete Anchors Exposed to Raw Water. In LRA Table 3.5.2-14, the applicant stated that SS concrete anchors exposed to raw water will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The AMR item cites generic Note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that, although not for this component, this material and environment combination is identified in the GALL Report, which states that SS piping, piping components, and piping elements exposed to raw water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

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 3.0.3.2.21. The staff finds the applicant's proposal to manage the effects of aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program acceptable because with implementation of the program enhancements, the AMP will require that steel components subject to RG 1.127 be inspected for loss of material.

Galvanized Steel Concrete Embedments Exposed to Raw Water. The staff's evaluation for galvanized steel concrete embedments exposed to raw water, which will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and is associated with generic Note F, is documented in SER Section 3.5.2.3.7.

Below-Grade Exterior Reinforced Concrete (Inaccessible Areas) Exposed to Water-Flowing. The staff's evaluation for below-grade exterior reinforced concrete (inaccessible areas) exposed to water-flowing, which will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and which is associated with generic Note H, is documented in SER Section 3.5.2.3.7.

Stainless Steel Structural Bolting Exposed to Raw Water. The staff's evaluation for SS structural bolting exposed to raw water, which will be managed for loss of material by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and which is associated with generic Note G, is documented in SER Section 3.5.2.3.7.

The staff concludes for items in LRA Table 3.5.2-14 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.15 Structural Commodity Group—Summary of Aging Management Evaluation—LRA Table 3.5.2-15

Miscellaneous Galvanized Steel (Catwalks, Stairs, Handrails, Ladders, Platforms, etc.) Exposed to Raw Water. In LRA Table 3.5.2-15, the applicant stated that miscellaneous galvanized steel (catwalks, stairs, handrails, ladders, platforms, etc.) exposed to raw water will be managed for loss of material by the Structures Monitoring Program. The AMR item cites generic Note G. The AMR item cites plant-specific Note 7, which states that this material and environment applies to miscellaneous steel components in the river screen house and Essential Service Water Cooling Tower at Byron.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this material and environment description. The staff noticed that in GALL Report Section XI.C "Selected Definitions & Use of Terms for Describing and Standardizing Materials," the definition for galvanized steel states that in the presence of moisture, galvanized steel is classified under the category "steel." The staff also noticed that although not for this component, this material and environment combination is identified in the GALL Report, which indicates that steel components exposed to raw water are susceptible to loss of material. Based on its review of items in the GALL Report for the same material and environment combination, the staff finds that the applicant identified all credible aging effects for this material and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because steel SCs will be visually examined for loss of material due to corrosion at a frequency not to exceed 5 years, which is consistent with the recommendations in the GALL Report.

Aluminum, Galvanized Steel, and Stainless Steel Insulation Jacketing Exposed to Air-Indoor, Uncontrolled. In LRA Table 3.5.2-15, revised by letter dated February 27, 2014, in response to RAI 3.5.2-4, the applicant stated that aluminum, galvanized steel, and SS insulation jacketing exposed to air-indoor, uncontrolled will be managed for loss of thermal insulation jacketing integrity by the External Surfaces Monitoring of Mechanical Components Program. The AMR items cite generic Note H. The AMR items cite plant-specific Note 10, which states, "loss of thermal insulation jacketing integrity is an applicable aging effect for this component type. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) AMP includes periodic visual inspection to ensure that the integrity of thermal insulation jacketing is maintained such that moisture intrusion is prevented."

The staff noticed that, although the applicant cited generic Note H for these items, the applicant proposes to manage the aging effects using the External Surfaces Monitoring of Mechanical Components Program, which is consistent with the recommendations in LR-ISG-2012-02. The staff also noticed that the applicant has identified loss of material due to pitting and crevice corrosion as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.5.2-15.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.9. The staff finds the applicant's proposal to manage loss of thermal insulation jacketing integrity using the External Surfaces Monitoring of Mechanical Components Program acceptable because the external visual inspections of the insulation jacketing, at a frequency not to exceed one refueling outage, is capable of detecting a loss of material for metallic components and identifying damage to the jacketing that would permit in-leakage of moisture.

Polymer Conduit Exposed to Air with Borated Water Leakage. In LRA Table 3.5.2-15, the applicant stated that polymer conduit exposed to air with borated water leakage will be managed for change in material properties by the Structures Monitoring Program. The AMR item cites generic Note J. The AMR item cites plant-specific note 3, which states, "this material and environment applies to the vinyl covering on flexible, liquid-tight conduit in air with borated water leakage environment…."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of Comprehensive Analytical Chemistry, Volume 53—Molecular Characterization and Analysis of Polymers (Elsevier, John M. Chalmers, Robert J. Meier, 2008), that staff noted that polymer degradation may lead to various effects including loss of gloss, discoloration, and the appearances of cracks in the surface, which may be indicative of a change in material properties. Therefore, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because periodic visual inspections are capable of detecting loss of gloss, discoloration, and cracking in the surface of the vinyl covering, which may be indicative of a change in material properties.

Calcium Silicate, Ceramic Fiber, and Fiberglass Insulation Exposed to Air-Outdoor. In LRA Table 3.5.2-15, the applicant stated that calcium silicate, ceramic fiber, and fiberglass insulation exposed to air-outdoor will be managed for change in material properties and loss of material by the Structures Monitoring Program. The AMR items cite generic Note J.

The staff reviewed the associated items in the LRA and the response to RAI 3.5.2-4, dated February 27, 2014, and noticed that the insulation on outdoor piping, piping components, and tanks, is covered by metallic jacketing. In its response, the applicant stated that "the specifications for insulation, which includes the jacketing, provide requirements to ensure that the jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams)." The staff also noticed that with proper installation of jacketing and in the absence of moisture, these materials are not likely to experience a change in material properties or loss of material. Overall, the applicant's proposal to manage change in material properties and loss of material for these materials is acceptable because the applicant addressed loss of material for aluminum insulation jacketing exposed to air-outdoor in LRA Table 3.5.2-15.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.20. The staff finds the applicant's proposal to manage the effects of aging using the Structures Monitoring Program acceptable because (1) the scope of the Structures Monitoring Program has been enhanced to include inspection of these components; (2) the calcium silicate, ceramic fiber, and fiberglass insulation is protected by metallic jacketing, which is installed in accordance with plant-specific requirements by knowledgeable personnel, and can ensure that moisture will not enter the insulation; and (3) the periodic visual inspections performed under the Structures Monitoring Program will identify loss of material for the insulation jacketing.

PVC Conduit Exposed to Groundwater/Soil. In LRA Table 3.5.2-15, the applicant stated that for PVC conduit exposed to groundwater/soil, there is no aging effect and no AMP is proposed. The AMR items cite generic Note J.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. While the staff recognizes that there are no AMR items for PVC conduit exposed to groundwater/soil, the "scope of program" program element of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks,'" states, "[t]his program manages the effects of aging for buried and underground piping and tanks constructed of any material including metallic, polymeric, cementitious, and concrete materials." Although conduit is not within the scope of LR-ISG-2011-03, the interim staff guidance (ISG) provides the staff insight that buried polymeric components have aging effects that should be managed. LRA Table 3.5.2-15 states that the intended functions of the buried conduit are shelter protection and structural support. Although these intended functions are different than that associated with buried piping, which is typically pressure boundary, leaks in the conduit could adversely impact the intended function of the cables that are inside the conduit if the cable jacketing was degraded.

It is not clear to the staff how buried conduit with intended functions of shelter protection and structural support will have no aging effects and no recommended AMP. By letter dated February 6, 2014, the staff issued RAI 3.5.2-2 requesting that the applicant state the basis for why potential aging effects for buried PVC conduit with intended functions of shelter protection and structural support are not being age-managed or propose an AMP to manage the aging effects.

In its response dated February 27, 2014, the applicant stated that the PVC conduit is embedded in concrete duct banks. Based on further review, the conduit does not have an intended function for license renewal, but rather provided an opening in the concrete duct banks when the concrete was poured and served as an aid for cable pulling. The reinforced concrete duct banks provide the shelter protection and structural support. No portions of PVC conduit containing in-scope cables are routed directly in soil. As a result, LRA Table 3.5.2-15 was revised to remove PVC conduit exposed to groundwater/soil.

The staff found that the applicant's Structures Monitoring program includes an enhancement (Enhancement No. 5) that requires: (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason. The staff finds the applicant's response acceptable because the PVC conduit does not perform a CLB intended function, the buried concrete duct banks are addressed in LRA Table 3.5.2-18, and the Structures Monitoring program will address aging effects associated with the buried concrete duct banks. The staff's concern described in RAI 3.5.2-2 is resolved.

<u>Polymeric Conduit Exposed to Air-Indoor Uncontrolled</u>. In LRA Table 3.5.2-15, the applicant stated that for polymeric conduit exposed to air-indoor uncontrolled, there is no aging effect and no AMP is proposed. The AMR items cite generic Note J. The AMR items cite plant-specific Note 2, which states, "[t]his material and environment applies to the vinyl covering on flexible, liquid-tight conduit in air – indoor environment. Based on plant OE, there are no AERM for the combination of these materials and environments. The material in this environment is not expected to experience significant aging effects."

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noticed that vinyl materials can be supplied in a wide range of compositions. Depending upon the composition, environmental factors such as temperature, radiation, and proximity to fluorescent lighting which emits UV radiation can affect the manner in which the component ages. The staff lacks sufficient information to determine that there are no aging effects associated with these components. By letter dated February 6, 2014, the staff issued RAI 3.5.2-3 requesting that the applicant state (a) the specific composition of the vinyl covering on flexible, liquid-tight conduit, (b) specific values of environmental factors in the various or worst case locations where the vinyl covering on flexible, liquid-tight conduit is located, and (c) the basis for why there are no aging effects to manage for the vinyl covering on flexible, liquid-tight conduit.

In its response dated February 27, 2014, the applicant stated that the specific composition of the vinyl polymer covering and environmental factors are not known. As a result, LRA Table 3.5.2-15 was revised to state that the Structures Monitoring program will be used to manage change in material properties for this material.

The staff finds the applicant's response and its proposal to manage the effects of aging using the Structures Monitoring program acceptable because: (a) the program, as documented in SER Section 3.0.3.2.20 conducts visual inspections every 5 years; (b) the program includes an enhancement (Enhancement No. 12) to accompany visual inspections with feeling or manipulating elastomeric components; (c) periodic visual examinations accompanied by manipulation are capable of detecting change in material properties for this material; (d) inspections every 5 years accompanied by the material being on the external surfaces of the conduit, and therefore visible during routine personnel traffic (degraded conditions would be documented in the CAP), are sufficient to detect changes in the material; and (e) to date, plant-specific OE has not shown any aging effects. The staff's concern described in RAI 3.5.2-3 is resolved.

<u>Thermal Insulation Exposed to Air-Indoor Uncontrolled and Air with Borated Water Leakage</u>. In LRA Table 3.5.2-15, the applicant stated that for thermal insulation exposed to air-indoor uncontrolled and air with borated water leakage and composed of calcium silicate, ceramic fiber, fiberglass, foamed plastic, and mineral fiber, there is no aging effect and no AMP is proposed. The AMR items cite generic Note J. The AMR items cite plant-specific Note 4, which states, "[o]perating experience has shown the air-indoor uncontrolled and air with borated water leakage environments to contain insignificant quantities of moisture, humidity, condensation, and contaminants during normal operation. Therefore, there are no aging effects associated with the insulation material in the normally dry, air - indoor uncontrolled and air with borated water leakage environments."

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noticed that:

- In a normally dry environment without the potential for water leakage, spray, or condensation, most insulation materials are expected to be inert to environmental effects. However, in moist environments, many insulation materials have been found to degrade. Some have the potential for prolonged retention of any moisture to which they are exposed; prolonged retention of moisture may increase thermal conductivity, thereby degrading the insulating characteristics, and also could accelerate the aging of insulated components.
- The description of air-indoor uncontrolled in LRA Table 3.0-1, "Byron and Braidwood Service Environments," includes the statement, "[s]urfaces of components in this environment may be wetted, but only rarely; equipment surfaces are normally dry." Although the surfaces are only rarely wetted in this air environment, insulation can retain the moisture and its ability to reduce heat transfer will be degraded. The staff infers from the description of the air with borated water leakage environment that leakage from components in the vicinity could impact insulation.
- LRA Table 3.5.2-15 includes insulation jacketing which, if properly installed, provides protection from ambient moisture for the insulating materials.

By letter dated February 6, 2014, the staff issued RAI 3.5.2-4 requesting that the applicant state whether all in-scope insulation is covered by jacketing and how the configuration control plant-specific procedures for jacketing ensure that the jacketing is properly installed so as to prevent water intrusion into the insulation. In its response dated February 27, 2014, the applicant stated that:

- All in-scope insulation is covered by metallic or nonmetallic jacketing (i.e., water resistant coatings or fabrics) jacketing.
- The specifications for insulation jacketing include requirements to ensure that the jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams).

- Based on a review of the corrective action program database, it is concluded that insulation not properly installed in accordance with the specifications would be identified during system walkdowns and appropriately corrected in accordance with the corrective action program. Therefore, it can be reasonably concluded that currently installed jacketing is properly installed so as to prevent water intrusion into the insulation.
- Personnel knowledgeable of proper insulation installation requirements perform the insulation repairs.
- A revision is required to the specific procedures or work order instructions for insulation and jacketing to formally document that the insulation and jacketing is properly installed during repairs so as to prevent water intrusion into the insulation. As noted below, LRA Sections A.2.1.23 and B.2.1.23 were revised to ensure these changes are implemented.
- A review of plant-specific OE indicates that the only significant quantities of moisture in thermal insulation in indoor environments have been identified as part of the resolution of leakage from the insulated piping and components themselves, and not due to drips or sweating from nearby components.

The staff noticed that:

- LRA Table 3.5.2-15 was revised to state that loss of thermal insulation jacketing integrity would be managed by the External Surfaces Monitoring of Mechanical Components program for jacketing exposed to air-indoor controlled and air with borated water leakage. As a result of this change, the line items In LRA Table 3.5.2-15 for thermal insulation exposed to air-indoor uncontrolled and air with borated water leakage and composed of calcium silicate, ceramic fiber, fiberglass, foamed plastic, and mineral fiber will continue to reflect no aging effect and no AMP; however, they were revised to cite generic note I and plant-specific note 4. Plant-specific note 4 states in part that insulation within the scope of license renewal is covered by water resistant jacketing and plant-specific configuration control procedures will ensure that jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams).
- LRA Table 3.4.1 was revised to add items 3.4.1-64 and 3.4.1-65 (from LR-ISG-2012-02). These items state that reduced thermal insulation resistance due to moisture intrusion is not an applicable aging effect because insulation within the scope of license renewal is covered by water-resistant jacketing. As stated above, items have been added to LRA Table 3.5.2-15 to manage loss of thermal insulation jacketing integrity by the External Surfaces Monitoring of Mechanical Components program.
- LRA Sections A.2.1.23 and B.2.1.23 were revised to state that: (a) periodic system walkdowns will include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained such that in-leakage of water would not be permitted and (b) procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation. Commitment No. 23 was also revised to reflect these changes.

The staff finds the applicant’s response and its proposal that the thermal insulation has no AERM acceptable because (a) all in-scope thermal insulation is protected by water-resistant jacketing installed in accordance with plant-specific requirements by knowledgeable personnel, which can ensure that moisture will not enter the insulation; (b) plant-specific OE has demonstrated that degraded insulation is documented in the CAP therefore ensuring that the jacketing is properly installed or will be corrected; (c) plant-specific OE has shown that it is unlikely that moisture has entered insulation due to adjacent pipe leakage or sweating; and (d) the LRA has been revised to require periodic (refueling outage interval) visual inspections that are capable of detecting degradation of insulation jacketing. The staff's concern described in RAI 3.5.2-4 is resolved.

<u>Carbon Steel Components Exposed to Air with Borated Water Leakage</u>. The staff's evaluation for carbon steel components exposed to air with borated water leakage, for which the applicant did not include AMR items for loss of material due to general, pitting, and crevice corrosion, is documented in SER Section 3.2.2.3.1.

<u>Lead (Pb) Penetration Seals Exposed to an Indoor Air-Uncontrolled Environment and an Indoor Air with Borated Water Leakage Environment</u>. In LRA Table 3.5.2-15, the applicant stated that, for lead (Pb) penetrations seals exposed to indoor air and indoor air with borated water leakage environments, there is no aging effect and no AMP is proposed. The AMR items cite generic Note J, which states that neither the component nor the materials and environment for the components are evaluated in the GALL report. The AMR items for evaluating the lead penetration seals also reference plant-specific Note 9 as the basis for the applicant's conclusion that there are no AERM for these penetration seals under exposure to air-indoor uncontrolled and air with borated water leakage environments. In Note 9 to LRA Table 3.5.2-15, the applicant stated that the AMR items apply to lead wool that is used for packing the penetrations and for radiation shielding. The applicant stated that OE has shown that the air-indoor uncontrolled and air with borated water leakage environments contain insignificant quantities of moisture, humidity, condensation, and contaminants during normal operation, and therefore, there are no aging effects associated with the lead packing wool materials in the indoor air-uncontrolled and air with borated water leakage environments.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environmental combination. The staff noticed that under normal indoor air conditions, any humidity, moisture, or condensation would induce formation of a passive oxide film on the lead materials that would make the materials resistant to general corrosion. However, the staff also noticed that the applicant had identified the indoor air with borated water leakage environment as an applicable external environment for the lead packing wool used in the penetration seals. The staff noticed that the applicant's plant-specific basis in Note 9 did not address whether postulated sources of borated water leakage could induce loss of material in the lead packing wool as a result of boric acid induced corrosion. As a result, the staff determined that it needed further justification to support a basis that a postulated borated water leakage environment would not induce loss of material in the lead packing wool or why loss of material due to borated water leakage would not need to be identified as an aging effect for the packing wool and managed during the period of extended operation.

By letter dated May 19, 2014, the staff issued RAI 3.5.2.3.15-1 requesting that the applicant provide further justification why the lead packing wool would not be subject to loss of material induced by boric acid corrosion under exposure to a leaking boric acid water source, particularly if the leaking boric acid solution was hot. The staff also asked the applicant to justify why an AMP had not been posed to manage potential loss of material in the lead packing wool under exposure to postulated boric acid leaks.

The applicant responded to RAI 3.5.2.1.15-1 in a letter dated June 5, 2014. In its response the applicant stated the lead material (i.e., lead packing wool) identified for penetration seals in LRA

Table 3.5.2-15 was included to account for a description in UFSAR Section 12.3.2.3 related to the potential use of lead wool as one of a series of higher density materials that might be used for penetration shielding. However, the applicant stated that, based on further review of plant drawings and design specifications, as well as a review of over 10 years of OE at Byron and Braidwood, no instances were identified regarding the actual use of lead packing wool as an applicable containment penetration seal material. As a result, the applicant stated that the list of materials in LRA Section 3.5.2.1.15 is being amended to remove lead as a referenced packing material. The applicant also stated that LRA Table 3.5.2-15 is revised to remove the AMR items for lead penetration seals and to include two new AMR items for elastomeric penetrations seals under exposure to "air – indoor uncontrolled" and "air with borated water leakage" environments. The applicant stated that, in these AMRs, shielding is the applicable intended function for the actual containment penetration seals that are included in the plant designs and that loss of sealing function is the potential aging effect for exposure of the elastomeric seals under exposure to these environments. In these AMRs, the applicant credited its Structures Monitoring Program as the basis for managing loss of sealing functions in the containment penetration seals.

The staff reviewed the applicant's response to RAI 3.5.2.3.15-1 and determined that the applicant's amendments of the LRA adequately clarified that elastomeric materials were the actual materials used in the design of the containment penetration seals at BBS. The staff noticed that the applicant's amended AMR items for these elastomeric containment seal materials under exposure to the "air – indoor uncontrolled" and "air with borated water leakage" environments was consistent with the GALL Report recommended AMR for managing loss of sealing in these components, as stated in Item III.A6.TP-7 in GALL Report Table III.A6. The staff also noticed that based on this AMR, the Structures Monitoring Program is an acceptable AMP to monitor and manage potential loss of sealing that may occur in these penetration seals during the period of extended operation. Therefore, the staff finds the applicant's amended basis to be acceptable because: (a) the applicant will use the Structures Monitoring Program to manage loss of sealing in the containment penetration seals at BBS and (b) the staff confirmed that the applicant's amended AMR basis is consistent with the recommended basis in AMR Item III.A6.TP-7 of the GALL report. The staff's concern in RAI 3.5.2.3.15-1 is resolved.

The staff concludes for items in LRA Table 3.5.2-15 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.16 Switchyard Structures—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 switchyard structures component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the switchyard structures component groups are consistent with the GALL Report.

3.5.2.3.17 Turbine Building Complex—Summary of Aging Management Evaluation—LRA Table 3.5.2-17

Polymer Windows Exposed to Air-Indoor (Uncontrolled). The staff's evaluation for polymer windows exposed to air-indoor (uncontrolled), which will be managed for change in material properties by the Structures Monitoring Program and is associated with generic note J, is documented in SER Section 3.5.2.3.14.

Polymer Windows Exposed to Air-Outdoor. The staff's evaluation for polymer windows exposed to air-outdoor, which will be managed for change in material properties by the Structures Monitoring Program and is associated with generic Note J, is documented in SER Section 3.5.2.3.14.

The staff concludes for items in LRA Table 3.5.2-17 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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).

3.5.2.3.18 Yard Structures—Summary of Aging Management Evaluation—LRA Table 3.5.2-18

The staff reviewed LRA Table 3.5.2-18, which summarizes the results of AMR evaluations for the yard structures component groups. The staff's review did not identify any AMR items with Notes F through J, indicating that the combinations of component type, material, environment, and AERM for the yard structures component groups are consistent with the GALL Report.

3.5.3 Conclusion

The staff concludes that 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).

3.6 Aging Management of Electrical and Instrumentation and Controls

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and instrumentation and control (I&C) components and commodity groups of:

- cable connections (metallic parts)
- connector contacts for electrical connectors exposed to borated water leakage
- fuse holders (not part of active equipment): metallic clamps
- high-voltage insulators
- insulation material for electrical cables and connections
- MEB
- switchyard bus and connections, transmission conductors, and transmission connectors

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides the applicant's evaluation results for those electrical and I&C components and component groups identified in LRA Section 2.5, "Scoping and Screening Results: Electrical," as being subject to an AMR. LRA Table 3.6 1, "Summary of Aging Management Evaluations for Electrical Components," is a summary comparison of the applicant's AMRs with the electrical and I&C components and component groups evaluated in the GALL Report.

The applicant stated that the electrical penetrations at BBS are environmentally qualified and are not subject to their own AMR but addressed as a TLAA and with aging management under the Environmental Qualification (EQ) of Electric components program. Electrical components, including electrical continuity, electrical insulation, and containment isolation fuses/breakers with the potential to be subjected to adverse localized environments are addressed as part of the aging management of insulation material for electrical cables and connections commodity group. The pressure boundary intended functions of electrical penetrations are addressed under LRA Scoping and Screening Results, Section 2.4.4, “Containment Structure.”

The applicant’s AMRs evaluated and incorporated applicable plant-specific and industry OE in the determination of AERMs. The plant-specific evaluation included plant documentation, drawings, and plant equipment databases.

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 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 reviewed the AMR line items and associated AMPs to ensure, as the applicant claimed, that certain AMRs and associated AMPs 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 AMP evaluations are documented in SER Section 3.0.3. Details of the staff’s AMR line- item evaluations are documented in SER Section 3.6.2.1.

The staff reviewed AMR line items consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant’s further evaluations were consistent with SRP-LR Section 3.6.2.2 acceptance criteria. The staff’s evaluations are documented in SER Section 3.6.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all applicable aging effects had been identified and whether the aging effects listed were appropriate for the material environment combinations specified. Additionally, for electrical and I&C components that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line-items and the plants’ OE to verify the applicant’s claims. The staff’s evaluation is documented in SER Section 3.6.2.3.

Table 3.6-1 summarizes the staff’s evaluation of electrical and I&C component materials, environments, aging mechanisms, aging effects, and the associated AMP(s), listed in LRA Section 3.6 and addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and I&C in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of Various polymeric and metallic materials exposed to adverse localized environment caused by heat, radiation, oxygen, moisture, or voltage (3.6.1-1)	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	EQ is a TLAA to be evaluated for the period of extended operation. See the SRP-LR Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See Chapter X.E1, "Environmental Qualification (EQ) of Electric Components," of this report for meeting the requirements of 10 CFR 54.21(c)(1)(iii) .	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.6.2.2.1)
High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor (3.6.1-2)	Loss of material due to mechanical wear caused by wind blowing on transmission conductors	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.6.2.2.2)
High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor (3.6.1-3)	Reduced insulation resistance due to presence of salt deposits or surface contamination	A plant-specific AMP is to be evaluated for plants located such that the potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution)	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.6.2.2.2)
Transmission conductors composed of aluminum; steel exposed to air – outdoor (3.6.1-4)	Loss of conductor strength due to corrosion	A plant-specific AMP is to be evaluated for aluminum conductor steel reinforced (ACSR)	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.6.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Transmission connectors composed of aluminum; steel exposed to air – outdoor (3.6.1-5)	Increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.6.2.2.3)
Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air – outdoor (3.6.1-6)	Loss of material due to wind-induced abrasion; Increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.6.2.2.3)
Transmission conductors composed of aluminum; steel exposed to air – outdoor (3.6.1-7)	Loss of material due to wind-induced abrasion	A plant-specific AMP is to be evaluated for aluminum conductor aluminum alloy reinforced (ACAR) and ACSR	Yes	Not applicable	Not applicable to Byron and Braidwood (see SER Section 3.6.2.2.3)
Insulation material for electrical cables and connections (including terminal blocks, fuse holders, etc.) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to adverse localized environment caused by heat, radiation, or moisture (3.6.1-8)	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Chapter XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Insulation material for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to adverse localized environment caused by heat, radiation, or moisture (3.6.1-9)	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Chapter XI.E2, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	No	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program	Consistent with the GALL Report
Conductor insulation for inaccessible power cables greater than or equal to 400 V (e.g., installed in conduit or direct buried) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to adverse localized environment caused by significant moisture (3.6.1-10)	Reduced insulation resistance due to moisture	Chapter XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
MEB: enclosure assemblies composed of elastomers exposed to air – indoor, controlled or uncontrolled or air – outdoor (3.6.1-11)	Surface cracking, crazing, scuffing, dimensional change (e.g., "ballooning" and "necking"), shrinkage, discoloration, hardening and loss of strength due to elastomer degradation	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Metal Enclosed Bus Program	Consistent with the GALL Report
MEB: bus/connections composed of various metals used for electrical bus and connections exposed to air – indoor, controlled or uncontrolled or air – outdoor (3.6.1-12)	Increased resistance of connection due to the loosening of bolts caused by thermal cycling and ohmic heating	Chapter XI.E4, "Metal Enclosed Bus"	No	Metal Enclosed Bus Program	Consistent with the GALL Report
MEB: insulation; insulators composed of porcelain; xenoy; thermo-plastic organic polymers exposed to air – indoor, controlled or uncontrolled or air – outdoor (3.6.1-13)	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics/ thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	Chapter XI.E4, "Metal Enclosed Bus"	No	Metal Enclosed Bus Program	Consistent with the GALL Report
MEB: external surface of enclosure assemblies composed of steel exposed to air – indoor, uncontrolled or air – outdoor (3.6.1-14)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to Byron and Braidwood

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
MEB: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor (3.6.1-15)	Loss of material due to pitting and crevice corrosion	Chapter XI.E4, “Metal Enclosed Bus,” or Chapter XI.S6, “Structures Monitoring”	No	Metal Enclosed Bus Program	Consistent with the GALL Report
Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, uncontrolled (3.6.1-16)	Increased resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply); fatigue due to ohmic heating, thermal cycling, electrical transients	Chapter XI.E5, “Fuse Holders”	No	Fuse Holders (Byron only) program	Byron: Consistent with the GALL Report Braidwood: Not applicable
Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, controlled or uncontrolled (3.6.1-17)	Increased resistance of connection due to fatigue caused by frequent manipulation or vibration	Chapter XI.E5, “Fuse Holders” No AMP is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms or fatigue caused by frequent manipulation or vibration	No	Fuse Holders (Byron only) program	Byron: Consistent with the GALL Report Braidwood: Not applicable

Component Group (SRP-LR Item No.)	Aging Effect/ Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air – indoor, controlled or uncontrolled or air – outdoor (3.6.1-18)	Increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Chapter XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	Consistent with the GALL Report
Connector contacts for electrical connectors exposed to borated water leakage composed of various metals used for electrical contacts exposed to air with borated water leakage (3.6.1-19)	Increased resistance of connection due to corrosion of connector contact surfaces caused by intrusion of borated water	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion Program	Consistent with the GALL Report
Transmission conductors composed of aluminum exposed to air – outdoor (3.6.1-20)	Loss of conductor strength due to corrosion	None - for Aluminum Conductor Aluminum Alloy Reinforced (ACAR)	None	Consistent with the GALL Report	Consistent with the GALL Report
Fuse holders (not part of active equipment): insulation material, MEB: external surface of enclosure assemblies composed of Insulation material: Bakelite; phenolic melamine or ceramic; molded polycarbonate; other, galvanized steel; aluminum, steel exposed to air – indoor, controlled or uncontrolled (3.6.1-21)	None	None	NA - No AEM or AMP	Consistent with the GALL Report	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 Consistent with the GALL Report

LRA Section 3.6.2.1 identifies the materials, environments, and AERMs, and the following programs that manage aging effects for the electrical and I&C components:

- Cable Connections (Metallic Parts)
- Connector Contacts for Electrical Connectors Exposed to Borated Water Leakage
- Fuse Holders (Not Part of Active Equipment): Metallic Clamps
- High-Voltage Insulators
- Insulation Material for Electrical Cables and Connections
- Metal Enclosed Bus
- Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors

In LRA Table 3.6.1, "Summary of Aging Management Evaluations for Electrical Components," the applicant provides a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical and I&C components, and component groups.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report 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 noticed for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A–E, indicating how the AMR is consistent with the GALL Report.

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

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

Note C indicates that the component for the AMR item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. Note C 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 items to confirm consistency with the GALL Report. The staff also determined whether the AMR item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

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

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect but credits a different AMP. The staff reviewed these items to confirm 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.

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 confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

3.6.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.6.1, item 3.6.1-14, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at BBS. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

3.6.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.6.2.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the electrical and I&C components and provides information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ
- reduced insulation resistance due to presence of any salt deposits and surface contamination, and loss of material due to mechanical wear caused by wind blowing on transmission conductors

- loss of material due to wind-induced abrasion, 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 GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.2.2.2. The staff's review of the applicant's further evaluation follows.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

LRA Section 3.6.2.2.1 associated with LRA Table 3.6 1, item 3.6.1-1, is a TLAA to be evaluated for the period of extended operation. Environmental Qualification (EQ) components are subject to replacement or refurbishment, if not qualified for the current licensing term, before exceeding a component's qualified life unless additional qualified life is established through ongoing qualification.

TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1). SER Section 4.4, "Environmental Qualification of Electric Component's" documents the staff's review of the applicant's evaluation of this TLAA. The staff's evaluation of LRA Section B.3.1.3, "Environmental Qualification (EQ) of Electric Components," which is credited by the applicant to manage or monitor EQ component aging mechanisms and effects, is addressed in SER Section 3.0.3.1.20. The applicant's EQ program also includes EQ of mechanical components qualified in accordance with Criterion 4, "Environmental and Dynamic Effects Design Basis" of Appendix A to 10 CFR Part 50. SER Section 4.7.3 addresses the TLAA for MEQ equipment.

3.6.2.2.2 Reduced Insulation Resistance Due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material Due to Mechanical Wear Caused by Wind Blowing on Transmission Conductors

LRA Section 3.6.2.2.2 associated with LRA Table 3.6.1, items 3.6.1-2 and 3.6.1-3, addresses reduced insulation resistance due to presence of salt deposits and surface contamination, and loss of material due to mechanical wear caused by wind blowing on transmission conductors.

The applicant stated a large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. The applicant stated that BBS is not located near the seacoast but in a rural area where industrial airborne particle concentrations are comparatively low. The applicant also stated that minor high-voltage insulator contamination is washed away by rainfall or snow and cumulative build up has not been experienced at BBS. Operating experience at BBS shows that surface contamination is not a significant aging mechanism. The applicant therefore concluded that reduced insulation resistance due to surface contamination is not an applicable aging effect for high-voltage insulators at BBS.

The applicant also stated that BBS transmission conductors are designed and installed to account for wind loading and swaying. The applicant stated that BBS experience has shown that the transmission conductors do not normally swing and that when they do, due to substantial wind, they do not continue to swing for very long once the wind has subsided.

The applicant further stated that based on BBS design and confirmed by their OE, mechanical wear of high-voltage insulators caused by wind blowing on transmission lines or surface contamination is not an aging effect significant enough to cause a loss of function. The staff reviewed LRA Section 3.6.2.2.2 against the criteria in SRP-LR Section 3.6.2.2.2, and Branch Technical Position RLSB-1. Reduced insulation resistance due to salt deposits and surface contamination may occur in high-voltage insulators. The GALL Report recommends further evaluation of plant-specific AMPs for plants at locations of potential salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material due to mechanical wear caused by wind on transmission conductors may occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

Because BBS is not located in vicinity of neither salt water bodies nor industrial pollution, surface contamination of high-voltage insulators is minimized. In addition, rainfall and snow periodically wash away minor contamination; the glazed insulator surface also aids this contamination removal. Based on its review, the staff finds that reduced insulation resistance aging effect due to salt deposits or surface contamination of high-voltage insulators is not an aging mechanism requiring management at BBS.

The staff also notes that EPRI 1003057, "Plant Support Engineering License Renewal Handbook" states that mechanical wear in insulators is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of insulators can be caused by wind blowing the supported transmission conductor, causing it to swing. If this swing is frequent enough, it could cause wear in the metal contact point of the insulator string and between an insulator and supporting hardware. Although this mechanism is possible, industry OE has shown that the transmission conductors are designed not to normally swing but and when they do, (e.g., due to a substantial wind), transmission conductors do not continue to swing for a long period of time once the wind has subsided.

The applicant's review of plant-specific OE has not identified loss of material on high-voltage insulators due to mechanical wear. Based on its review, the staff finds the mechanical wear aging effect for high-voltage insulators is not an AERM at BBS.

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 finds that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will 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, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload

LRA Section 3.6.2.2.3 is associated with LRA Table 3.6.1, items 3.6.1-4 through 3.6.1-7, addressing loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connections due to oxidation or loss of preload of transmission conductors and connections, and switchyard bus and connections.

The applicant stated that the switchyard bus and connections, transmission conductors, and transmission connections evaluated by the applicant are those credited for recovery of offsite power following station blackout. Other transmission conductors are not subject to an AMR because they do not perform a license renewal intended function.

The applicant stated that in-scope transmission conductors subject to an AMR are the tie lines between the BBS 345-kV switchyard and the SATs and the short connections from switchyard buswork to gas circuit breakers.

The applicant also stated that the short connections between the gas circuit breakers and switchyard buswork for Byron only are all aluminum (AA) conductors which are not subject to aging management because AA conductors have the same characteristics as aluminum conductor aluminum alloy reinforced (ACAR) transmission conductors evaluated in the GALL Report. An AA transmission conductor consists of aluminum alloy wires in a multi-layer construction similar to ACAR transmission conductors except that the AA conductors do not have an aluminum alloy core. Therefore, the typical degradation of aluminum conductor steel reinforced (ACSR) conductors is not applicable for Byron AA transmission conductors.

The applicant stated that BBS tie line conductors are ACSR. ACSR transmission conductor loss of conductor strength is primarily due to the steel core of an ACSR conductor losing its galvanized coating over time causing a decrease in ultimate strength of the steel core. Corrosion rates are largely dependent on air quality. The applicant referenced an Ontario Hydro study that included the results of ACSR laboratory and field tests including the evaluation of conductor aging effects due to locations near pollution sources and major urban areas.

The applicant stated that the BBS in-scope tie line transmission conductors are of the same type (ACSR) as evaluated by the Ontario Hydro study and by EPRI 1003057, “Plant Support Engineering License Renewal Handbook.” The applicant confirmed that the test methodology used in the Ontario Hydro study was applicable to the BBS tie line transmission conductors. Additionally, the applicant stated that BBS is located in an area where industrial particle concentrations are comparatively low with no heavy industry nearby which is consistent with the transmission conductor environments evaluated by the Ontario Hydro study. The applicant confirmed that the design, physical construction, and conductor strength margin of the in-scope tie line transmission conductors are also consistent with the Ontario Hydro study results and EPRI 1003057, “Plant Support Engineering License Renewal Handbook” guidance.

Based on BBS design and plant-specific analysis, and confirmed by OE, the applicant concluded that the loss of tie line transmission conductor strength is not applicable to BBS and would not cause a loss of intended function for the period of extended operation. Therefore, the applicant concluded that in-scope tie line transmission conductor corrosion is not a credible aging effect that requires management for the period of extended operation.

The applicant stated that switchyard bus connections employ good bolting practices. The connections are treated with corrosion inhibitors to avoid connections oxidations and torqued at the time of installation to avoid loss of preload. Switchyard bus bolted connections are designed and installed using SS lock washers that provide vibration absorption and prevent loss of preload. The applicant also stated that switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components such as concrete footings and structural steel. Switchyard bus is rigidly mounted and is therefore not subject to abrasion induced by wind loading. The applicant further stated that BBS switchyards are not subject to a saline environment or industrial air pollution. It is located inland, in central Illinois, in an area where industrial airborne particle concentrations are comparatively low, since it is located in a rural area with no heavy industry nearby. The applicant also stated that aluminum bus material does not experience any appreciable aging effects in this environment.

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3, and Branch Technical Position RLSB-1 which states that loss of material due to wind induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

The staff concludes that the Byron AA transmission conductors between the gas circuit breakers and switchyard buswork have a high degree of corrosion resistance. The applicant's evaluation of AA transmission conductor aging is consistent with Item VI.A LP-46 of the GALL Report, which states that loss of conductor strength is not an applicable aging effect for similar transmission conductors. Therefore, the staff finds that loss of conductor strength due to corrosion of AA transmission conductors is not an applicable aging effect at Byron.

The Ontario Hydro study estimated mean ACSR transmission conductor longevity (depending on test method and environment) to be from 66 years to 81 years. The study concluded that a mean value of 70 years is considered a valid estimate for existing conductors. The Ontario Hydro study included an evaluation of transmission conductor aging due to environmental factors (e.g., rural, semi-rural, and urban industrial environment pollution). The staff finds that the environments evaluated are consistent with the BBS ACSR tie line transmission conductor environment. Based on the above, the staff finds that the applicant's tie line ACSR transmission conductors are bounded by the Ontario Hydro study, including adequate remaining margin in conductor strength. Therefore, the applicant's ACSR transmission conductors intended function will be maintained consistent with the CLB during the period of extended operation.

The staff noticed that switchyard buses are connected to flexible conductors that do not vibrate or swing and are supported by insulators and structural supports such as concrete footings and structural steel. Because there are no connections subject to movement or vibrating equipment, wind-induced abrasion and fatigue is not an applicable aging mechanisms for switchyard bus and connections at BBS.

The staff evaluation also concludes that the BBS switchyard buses are not exposed to industrial air pollution and that the aluminum bus material does not exhibit significant aging effects when exposed to this environment. In addition, BBS switchyard connections employ corrosion inhibitors and bolting practices using SS lock washers that prevent loss of preload and limit vibration. Therefore, the staff concludes that corrosion, oxidation, and loss of preload are not considered applicable aging mechanisms for BBS.

The staff noticed that wind born particulates have not been shown to be a contributor to loss of material at BBS. Wind fatigue is addressed in 3.6.2.2.2. Therefore, the staff finds that wind induced abrasion and fatigue are not significant AERMs for transmission conductors and connections at BBS.

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 finds that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.6.2.2.5 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of OE of AMPs.

3.6.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Table 3.6.2-1, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Table 3.6.2-1, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR 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 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.

The staff's evaluation is discussed in the following sections.

3.6.2.3.1 Electrical Commodities Summary of Aging Management Evaluation—LRA Table 3.6.2-1

In LRA Tables 3.6.1, Items 3.6.1-16 and 3.6.1-17, and Table 3.6.2-1, the applicant stated that for fuse holders an increased resistance of connection caused by metallic clamps exposed to air – indoor controlled and uncontrolled; increased resistance of connection due to chemical contamination, corrosion, and oxidation; fatigue due to ohmic heating, thermal cycling, electrical transients; and frequent manipulation or vibration are applicable to Byron only. No AMP for fuse holders (metallic clamp) is proposed for Braidwood.

The GALL Report, items VI.A.LP-31 and VI.A.LP-23 VI.A-8, "Fuse Holders (Not Part of active equipment): metallic clamps," identifies the aging effects and mechanism as increased resistance of connection due to chemical contamination, corrosion and oxidation or fatigue caused by ohmic heating, thermal cycling, and electrical transients, frequent manipulation or vibration. The associated AMP GALL Report, XI.E5, “Fuse Holders,” states that fuse holders within the scope of license renewal should be tested to provide an indication of the condition of the fuse holder metallic clamps.

The applicant identified the AERMs as noted below:

- Braidwood – Fuse holders (metallic clamps) have no AERMs.
- Byron – The following aging effects identified with fuse holders (metallic clamps) were found applicable to Byron.
    - increased resistance of connection
    - increased resistance of connection – fatigue

In LRA Table 3.6.2-1, the applicant indicated, via Note 8 that the combination of component type, material, environment and AERM for BBS does not correspond to the line item in the GALL Report. Note 8 states that based on the design and review of OE, increased resistance of connection is not an applicable aging effect for Braidwood fuse holders (metallic clamps). Note 8 further states that metallic clamps of in-scope fuse holders (not part of active equipment) at Braidwood are not subject to chemical contamination, corrosion, and oxidation and not subject to fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent manipulation, or vibration. The applicant also provided further information about how it will manage the applicable aging mechanisms and effects for Byron.

For component type, material, and environment combinations not consistent with or not addressed in the GALL Report, the staff reviewed the applicant’s evaluation to determine whether the applicant 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.

At BBS, a search of plant documents, controlled drawings, and plant equipment databases was performed by the applicant to identify fuse holders within the scope of License Renewal. The applicant’s search identified 68 fuse holders at Braidwood and 100 fuse holders at Byron within the scope of license renewal that are subject to an AMR.

The fuse holder search results for Braidwood identified fuse holders in two in-scope fire detection electrical distribution panels. The applicant concluded that the potential aging effects as discussed in the GALL Report are not applicable to the 68 in-scope fuse holders installed at Braidwood. The applicant stated that the two fire detection panels are located in an environment that does not subject them to environmental aging mechanisms. The applicant also stated that the fuses are protected from chemical contamination as they are installed in an enclosed electrical panel located in an environmentally controlled area (air conditioned). A walkdown of the in-scope fuse holders performed by the applicant confirmed that in-scope fuse holders showed no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. The applicant concluded that chemical contamination, corrosion, and oxidation are not applicable aging mechanisms for Braidwood in-scope fuse holders. The applicant also stated that the fuses are not subjected to ohmic heating, or thermal cycling based on the low operating current of the I&C circuit loads. In addition, the applicant stated that mechanical stress due to electrical faults and transients are limited by circuit protective devices and the infrequent and random nature of electrical faults. Further, the applicant stated that the in-scope fuse holders at Braidwood are not susceptible the wear and fatigue attributed to frequent manipulation or vibration aging mechanisms because the in-scope fuse holders are not points used for periodic testing, preventive maintenance or installed on equipment that would subject the fuse holders to vibration. The applicant concluded that electrical and thermal cycling, electrical transients, and frequent manipulation and vibration are not applicable aging mechanisms for the Braidwood in-scope fuse holders.

The applicant's search results for Byron identified 100 fuse holders within the scope of license renewal that are not part of active equipment. These fuse holders are located in 12 enclosed electrical panels. Ten of the enclosed electrical panels are located in the Byron auxiliary building. Eight of these electrical panels contain two fuse holders each. The remaining two electrical panels contain 30 fuse holders and 38 fuse holders, respectively. The remaining two enclosed electrical panels are located in the Byron river screen house and contain eight fuse holders each. The applicant provided the following basis for the conclusion that the fuse holders (metallic clamps) are or are not subject to the aging effects or mechanisms identified in the GALL Report Tabulation of Results, item VI.A-8.

The applicant concluded that the potential aging effects as discussed in the GALL Report are not applicable to the 16 fuse holders in the eight in-scope instrument power electrical panels (2 fuse holders in each electrical panel) nor to the 68 fuse holders in the two in-scope fire detection control power distribution panels at Byron. The applicant's evaluations of aging effects for Byron are discussed below.

The 10 electrical panels are located in the Byron auxiliary building electrical panel rooms in an environment that does not subject them to environmental aging mechanisms. The fuse holders are protected from chemical contamination, and are within a mild environment inside the Byron auxiliary building during normal conditions. There are no sources of chemicals in the vicinity of the electrical panels during normal conditions. The environment inside the room is air-conditioned by a ventilation system; thus they do not experience high relative humidity during normal conditions. The fuse holders are not subject to outside weather conditions and, therefore, are not subject to moisture from precipitation. An additional barrier that protects the fuse holders from exposure to moisture is their location inside an enclosed electrical panel. The fuse holders are not located in or near humid areas, and they are not exposed to industrial or oceanic environments.

The applicant conducted a walkdown of these electrical panels containing in-scope fuse holders to confirm that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation or corrosion. Therefore, the applicant concluded that chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

The fuse holders located in the Byron Auxiliary Building are for process instruments or fire detection control power. The loads are I&C circuits that operate at low currents where no appreciable thermal cycling or ohmic heating occurs. Therefore, the applicant determined that electrical and thermal cycling is not an applicable aging mechanism for these fuse holders.

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 because such faults are infrequent and random in nature. Therefore, the applicant does not consider electrical transients an applicable aging mechanism for these fuse holders.

Wear and fatigue is caused by repeated insertion and removal of fuses. The applicant determined that fuses in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are either clearance or isolation points that support periodic testing or preventive maintenance. These fuse holders are located in electrical panels that are 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. The applicant concluded that the metallic clamps of these fuse holders will not exhibit the aging effects or mechanisms of fatigue due to frequent manipulation or vibration.

Based on installed location, design configuration, operating service conditions, and OE, the 16 fuse holders in the eight in-scope instrument power electrical panels (2 fuse holders in each electrical panel) and the 68 fuse holders in the two in-scope fire detection control power distribution panels (38 fuse holders in one panel and 30 fuse holders in the other panel) located in the Byron auxiliary building are not susceptible to the aging effects and mechanisms associated with metallic clamps. Therefore, the applicant concluded that aging management activities are not required for these fuse holders.

The remaining 16 fuse holders at Byron serve the essential service water system, specifically the essential service water makeup pump battery charger fuses. They are in two enclosed electrical panels located in Byron River Screen House. Each enclosed electrical panel contains eight fuse holders. The indoor air uncontrolled environment at the River Screen House subjects the fuse holders to environmental aging mechanisms. Additionally, these fuse holders serve power circuits that can carry significant current and potentially expose the fuse holder metallic clamps to thermal fatigue in the form of increased resistance caused by thermal cycling and ohmic heating. Finally, these fuses are routinely manipulated during the battery charger surveillance tests, thus they are subject to fatigue caused by frequent manipulation or vibration.

Based on installed location, design configuration, and operating service conditions, these 16 fuse holders are susceptible to the aging effects and mechanisms associated with fuse holder metallic clamps. Therefore, the applicant concluded that aging management activities are required for the essential service water makeup pump battery charger fuse holders.

The staff finds the applicant evaluation of Byron fuse holders acceptable. The staff also concludes that in-scope fuse holder metallic clamps located at the Byron river screen house are susceptible to the following aging mechanisms and effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, frequent manipulation or vibration. A walkdown by the applicant and the GALL Report AMP XI.E5 audit performed by the staff confirmed the applicable aging mechanisms and effects for the metallic portion of in-scope fuse holders at Byron. The staff's evaluation of LRA AMP B.2.1.41, "Fuse Holders (Byron Only)" is in SER Section 3.0.3.1.18.

The staff finds the applicant's evaluation of Braidwood fuse holders acceptable because the fuses located in the Braidwood auxiliary building are not routinely pulled or manipulated for plant testing. In addition, Braidwood fuse holders located in the auxiliary building are enclosed in an electrical panel that provides protection against environmental aging mechanisms. Therefore, chemical contamination, corrosion, and oxidation are not applicable aging effects at Braidwood. Additionally, the Braidwood auxiliary building fuses are not heavily loaded because they are used in I&C circuits that do not experience thermal cycling or ohmic heating. Therefore, the ohmic heating and thermal cycling are not applicable stressors for in-scope Braidwood fuses located in the auxiliary buildings. Further, mechanical stress due to electrical faults is not considered a credible aging stressor because such faults are infrequent and because the fuse element design will interrupt the fault current. The stresses associated with faults are mitigated by the fast action of fuse elements. In addition, the fuses located in the Braidwood auxiliary building are not routinely pulled or manipulated for plant testing. Therefore, fatigue and mechanical stresses due to testing are not an applicable aging effect for these fuses. Finally, fuses located in the Braidwood auxiliary building are not mounted on equipment subject to movement or vibration. Therefore, vibration is not an applicable stressor for in-scope fuse holders located in the auxiliary buildings at Braidwood. A walkdown by the applicant and the GALL Report AMP XI.E5 audit performed by the staff confirmed the applicable aging mechanisms and effects for the metallic portion of in-scope fuse holders at Braidwood.

Based on its review, the staff finds the applicant's BBS fuse holder evaluation acceptable because the applicant evaluated the GALL Report AMP XI.E5 program, including aging mechanisms and effects, and provided adequate justification with regard to their applicability to BBS.

The staff concludes for items in LRA Table 3.6.2-1 with no AERMs that the applicant appropriately evaluated the material and environment combinations not addressed in the GALL Report, and 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 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," and LRA Appendix B, "Aging Management Programs." On the basis of its review of the AMR results and AMPs, the staff concludes that the applicant demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concludes that the 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 there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed license in accordance with the CLB, and that any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section of the safety evaluation report (SER) provides the staff of the U.S. Nuclear Regulatory Commission's (NRC's or the staff's) evaluation of Exelon Generation Company, LLC's (Exelon's or the applicant's) basis for identifying those plant-specific or generic analyses that need to be identified as time-limited aging analyses (TLAAs) for the applicant's license renewal application (LRA) and the list of TLAAs for the LRA. TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. This section of the SER also provides the staff's evaluation of the applicant's basis for identifying those exemptions that need to be identified in the LRA.

Pursuant to the requirements in Section 54.21(c)(1), of Title 10, *Code of Federal Regulations* (10 CFR 54.21(c)(1)), an applicant for license renewal must list all evaluations, analyses, and calculations in the current licensing basis (CLB) that conform to the definition of a TLAA, as defined in 10 CFR 54.3. Section 54.3 of 10 CFR states that a plant-specific or generic evaluation, analysis, or calculation is a TLAA if it meets all six of the following TLAA identification criteria:

(1) The evaluation, analysis, or calculation must involve a system, structure, or component (SSC) that is within the scope of license renewal, as mandated in 10 CFR 54.4(a).

(2) The evaluation, analysis, or calculation must consider the effect or effects of aging.

(3) The evaluation, analysis, or calculation must be based on time-limited assumptions that are defined by the current operating term (for example, 40 years).

(4) The evaluation, analysis, or calculation must have been determined to be relevant by the applicant in making a safety determination.

(5) The evaluation, analysis, or calculation must involve conclusions, or provide the basis for conclusions, related to the capability of the SSC to perform its intended function(s), as described in 10 CFR 54.4(b).

(6) The evaluation, analysis, or calculation must be contained or incorporated by reference in the CLB.

For each evaluation, analysis, or calculation that is a TLAA, the applicant must demonstrate that the TLAA will be acceptable for the period of extended operation in accordance with one of the following three acceptance criteria for TLAAs in 10 CFR 54.21(c)(1):

(i) demonstration that the evaluation, analysis, or calculations of record will remain valid for the period of extended operation

(ii) demonstration that the evaluation, analysis, or calculation has been projected to the end of the period of extended operation

(iii) demonstration that the impact of the effects of aging on the intended function(s) will be adequately managed during the period of extended operation

In the LRA, the applicant dispositioned each TLAA (i.e., identified the criterion satisfied) based on one of the above three acceptance criteria per 10 CFR 54.21(c)(1). The staff reviewed the applicant's disposition for each TLAA against the requirements per 10 CFR 54.21(c)(1).

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list all plant-specific exemptions in the CLB that were granted in accordance with the exemption approval criteria in 10 CFR 50.12 and that are based on a TLAA. For any such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

The staff's guidance for reviewing LRA Section 4.1 is given in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Section 4.1, Identification of Time Limiting Aging Analyses. SRP-LR Section 4.1.1 summarizes the areas of review. SRP-LR Section 4.1.2 provides the staff's "acceptance criteria" for performing TLAA and TLAA-based exemption identification reviews. SRP-LR Section 4.1.3 provides the staff's "review procedures" for performing the TLAA and TLAA-based exemption identification reviews. SRP-LR Table 4.1-1 provides examples on whether a given analysis would be required to be identified as a TLAA for an LRA. SRP-LR Table 4.1-2 provides a generic list of those analyses or calculations that are normally part of an applicant's CLB and thus are normally identified as TLAAs for an LRA. SRP-LR Table 4.1-3 provides a generic list of those analyses or calculations that may be identified as plant-specific TLAAs for an LRA.

Pursuant to 10 CFR 54.22, applicants must identify any facility technical specification (TS) changes or additions that are necessary to manage the effects of aging during the period of extended operation, along with a justification for those TS changes or additions.

4.1.1 Summary of Technical Information in the Application

4.1.1.1 Identification of TLAAs

The applicant stated that the list of TLAAs for the LRA was identified using methods that are consistent with those provided in the SRP-LR and 10 CFR Part 54, "Requirements for Renewal of Operating License for Nuclear Power Plants." The applicant stated that a list of potential TLAAs was assembled from the following sources: (a) the SRP-LR, (b) the Generic Aging Lessons Learned Report (GALL Report), (c) Nuclear Energy Institute (NEI) Report NEI-95-10, Revision 6, (d) NRC statement of considerations on 10 CFR Part 54, and (e) prior LRAs and associated NRC requests for additional information (RAIs) and SERs.

The applicant also stated that the following CLB and design basis documentation sources were searched to identify potential TLAAs: (a) the updated final safety analysis report (UFSAR) for the Byron and Braidwood Stations (BBS), (b) plant TSs and TS bases documents, (c) the plant Technical Requirements Manuals, (d) docketed licensing correspondence, (e) NRC SERs, (f) design basis documents (DBDs), (g) Westinghouse Electric Corporation (Westinghouse) design analyses and reports, (h) vendor design analyses and reports, and (i) environmental qualification (EQ) binders.

LRA Table 4.1-1 provides the applicant's comparison of the BBS TLAAs to those analyses that are listed as potential TLAAs in the SRP-LR. LRA Table 4.1-2 provides a summary listing of the TLAAs that the applicant has identified as being applicable to BBS and the criteria that are used to accept these TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii).

4.1.1.2 Identification of Exemptions

In LRA Section 4.1.5, the applicant stated that the exemptions for BBS were identified through a review of the UFSAR, the operating licenses, the TSs, NRC SERs, ASME Section XI program documentation, fire protection documents, the staff's Agencywide Documents Access and Management System (ADAMS) database, and docketed correspondence. The applicant stated that it identified the following regulatory exemptions that are based on a TLAA:

(a) Those exemptions that were granted on July 13, 1995, November 29, 1996, December 12, 1997, and January 16, 1998, which collectively permit the applicant to use ASME Code Case N-514 as the basis for establishing the low-temperature overpressure protection (LTOP) system enable temperature setpoints and for establishing the LTOP pressure lift setpoints at 110 percent of that which would be established using the methods of analysis in the ASME Code, Section XI, Appendix G.

(b) An exemption that was granted on August 8, 2001, allowing the applicant to use methodologies in ASME Code Cases N-588 and N-640 as alternative bases for generating the pressure-temperature (P-T) limit curves for BBS.

(c) An exemption that was granted on November 22, 2006, allowing the applicant to use the alternative methodology in Westinghouse Proprietary Report No. Westinghouse Commercial Atomic Power (WCAP)-16143-P for establishing the minimum temperature requirements for the P-T limit curves for BBS.

The applicant stated that all of these exemptions are based on the P-T limit curves that are in effect for 32 effective full-power years (EFPY) of operation. The applicant stated that, based on the EFPY projections described in LRA Section 4.2.1, the BBS units are expected to exceed 32 EFPY prior to entering the period of extended operation, thereby necessitating updates to the P-T limit curves in accordance with 10 CFR Part 50, Appendix G, prior to the period of extended operation. The applicant stated that it anticipates that these exemptions will not be required for the period of extended operation. The applicant clarified that if the BBS reactors do not reach 32 EFPY prior to the period of extended operation, the exemptions are acceptable for the period of extended operation because the staff did not place a limitation on the time of applicability for the exemptions.

4.1.1.3 Identification of Technical Specification Changes or Additions Needed to Manage Aging during the Period of Extended Operation

LRA Appendix D provides the applicant's evaluation regarding whether the LRA would need to include any facility TS changes or additions in order to manage the effects of aging during the period of extended operation. The applicant stated that it performed a review of the information in the LRA and the TS and determined that the LRA did not need to include any TS changes or additions to manage the effects of aging during the period of extended operation.

4.1.2 Staff Evaluation

4.1.2.1 Identification of TLAAs

The staff reviewed the applicant's methodology and results for identifying the TLAAs for the LRA against the six criteria for TLAA identification in 10 CFR 54.3 and the generic list of TLAAs in SRP-LR Section 4.1, including those in SRP-LR Tables 4.1-2 and 4.1-3 as applicable to the

CLB for the reactor units. The staff used the “acceptance criteria” in SRP-LR Section 4.1.2 and the “review procedures” in SRP-LR Section 4.1.3 as the basis for its review.

4.1.2.1.1 Evaluations, Analyses, and Calculations That Conform to the Definition of a TLAA, as Defined in 10 CFR 54.3

The staff noticed that LRA Table 4.1-2 identifies that the following analyses in the CLB meet the definition of a TLAA in 10 CFR 54.3:

- LRA Section 4.2 – Reactor Vessel Neutron Embrittlement Analysis
    - LRA Section 4.2.1, Neutron Fluence Projections
    - LRA Section 4.2.2, Upper-Shelf Energy
    - LRA Section 4.2.3, Pressurized Thermal Shock
    - LRA Section 4.2.4, Adjusted Reference Temperature
    - LRA Section 4.2.5, Pressure-Temperature Limits
    - LRA Section 4.2.6, Low Temperature Overpressure Protection (LTOP) Analyses
- LRA Section 4.3 – Metal Fatigue
    - LRA Section 4.3.1, Transient Inputs to Fatigue Analyses
    - LRA Section 4.3.2, ASME Code Section III, Class 1, Class 2, and Class 3 Fatigue Analyses
    - LRA Section 4.3.3, ASME Code Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analyses
    - LRA Section 4.3.4, Class 1 Component Fatigue Analyses Supporting GSI-190 Closure
    - LRA Section 4.3.5, Reactor Vessel Internals Fatigue Analyses
    - LRA Section 4.3.6, High-Energy Line Break (HELB) Analyses Based on Fatigue
    - LRA Section 4.3.7, NRC Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification
    - LRA Section 4.3.8, ASME Code Section III, Subsection NF, Class 1 Component Supports Allowable Stress Analyses
    - LRA Section 4.3.9, Fatigue Design of Spent Fuel Pool Liner and Spent Fuel Storage Racks for Seismic Events
    - LRA Section 4.3.10, Pressurizer Heater Sleeve Structural Assessment
- LRA Section 4.4 – Environmental Qualification (EQ) of Electric Components
- LRA Section 4.5 – Concrete Containment Tendon Prestress Analysis
- LRA Section 4.6 – Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses
    - LRA Section 4.6.1, Containment Liner Plates Fatigue
    - LRA Section 4.6.2, Containment Airlocks and Hatches Fatigue
    - LRA Section 4.6.3, Containment Electrical Penetrations Fatigue

- LRA Section 4.6.4, Containment Piping Penetrations Fatigue
- LRA Section 4.6.5, Fuel Transfer Tube Bellows Fatigue
- LRA Section 4.6.6, Recirculation Sump Guard Piping Bellows Fatigue

- LRA Section 4.7 – Other Plant-Specific TLAAs
    - LRA Section 4.7.1, Leak-Before-Break
    - LRA Section 4.7.2, Crane Load Cycle Limits
    - LRA Section 4.7.3, Mechanical Environmental Qualification
    - LRA Section 4.7.4, Residual Heat Removal Heat Exchangers Tube Side Inlet and Outlet Nozzles Fracture Mechanics Analysis
    - LRA Section 4.7.5, Reactor Coolant Pump Flywheel Crack Growth Analysis
    - LRA Section 4.7.6, Byron Unit 2 Pressurizer Seismic Restraint Lug Flaw Evaluation
    - LRA Section 4.7.7, Braidwood Unit 2 Feedwater Pipe Elbow Crack Growth Evaluation
    - LRA Section 4.7.8, Analyses Supporting Flaw Evaluations of Primary System Components

The staff determined that the applicant's identification of these TLAAs is consistent with the staff's list of generic TLAAs in SRP-LR Table 4.1-2, "Generic Time Limited Aging Analyses," and list of potential plant-specific TLAAs in SRP-LR Table 4.1-3, "Examples of Potential Plant-Specific TLAAs." Based on this review, the staff finds that the identification of these TLAAs is acceptable because it is in accordance with 10 CFR 54.21(c)(1). The staff's evaluation of the applicant's basis for accepting these TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) is documented in SER Sections 4.2 to 4.7 and their subsections.

4.1.2.1.2 Evaluation of Applicant's List of Evaluations, Analyses, and Calculations That Do Not Conform to the Definition of a TLAA, as Defined in 10 CFR 54.3

SRP-LR Table 4.1-2, "Generic Time Limited Aging Analyses," and SRP-LR Table 4.1-3, "Examples of Potential Plant-Specific Time Limited Aging Analyses," provide a collective list of analyses that may be part of an applicant's CLB and that may need to be identified as TLAAs in the LRA. Of the 14 potential plant-specific TLAAs listed in SRP-LR Table 4.1-3, the applicant identified 9 that were TLAAs for the LRA. These are the TLAAs listed in SER Section 4.1.2.1.1, which reference the TLAA in LRA Section 4.2.6 (i.e., the TLAA on LTOP) and the eight plant-specific TLAAs in LRA Sections 4.7.1 – 4.7.8. The staff reviewed the information in LRA Table 4.1-3 against the list of potential plant-specific TLAAs in SRP-LR Table 4.1-3 in order to evaluate the validity of the applicant's bases for not identifying the remaining analyses in SRP-LR Table 4.1-3 as TLAAs in the LRA. In addition, the applicant also identified that the containment corrosion analysis in LRA Table 4.1-2 is not applicable to the BBS CLB and does not need to be identified as a TLAA for the LRA. For the analyses that the applicant claimed were not TLAAs for the CLB, the staff's evaluations of the applicant's "absence of a TLAA" bases are given in the subsections that follow.

<u>Lack of an Inservice Local Metal Containment Corrosion Analysis</u>. SRP-LR Table 4.1-2 identifies inservice local metal containment (MC) corrosion analyses as a generic TLAA. The

SRP-LR identifies that these analyses may conform to the definition of a TLAA in 10 CFR 54.3(a) and need to be identified as TLAAs in accordance with 10 CFR 54.21(c)(1).

LRA Table 4.1-1 states that the CLB does not include any inservice local MC corrosion analyses that meet the definition of a TLAA in 10 CFR 54.3(a) or would need to be identified as TLAAs in accordance with the requirement in 10 CFR 54.21(c)(1).

The staff reviewed UFSAR Section 6.2.1 to evaluate the validity of the applicant's basis for its conclusion. UFSAR Section 6.2.1 identifies that the containment structures are designed as prestressed-concrete shell structures, with each structure being made up of a cylinder with a shallow dome roof and a flat foundation slab. The UFSAR states that each containment structure is lined on the inside with steel plate, which acts as a leak tight membrane. The staff noticed that the reactor units are not designed with metallic containment structures. As such, the staff concludes that the CLB does not include this type of plant-specific TLAA because the staff has confirmed the reactor designs do not rely on metallic containment structures as the basis for maintaining containment integrity during normal operating conditions, transient operating conditions, or postulated loss-of-coolant accident (LOCA) conditions.

<u>Lack of a TLAA for Evaluating Intergranular Separations in the Heat Affected Zones (HAZ) of Reactor Vessel Low-Alloy Steel Forging Components</u>. SRP-LR Section 3.1.2.2.5 identifies that SA-508, Class 2 forging components in Babcock & Wilcox (B&W)-designed reactor vessels may be susceptible to cracking in the welds that join the reactor vessel cladding to the reactor vessel forging components. SRP-LR Table 4.1-3 identifies that the CLB for pressurized-water reactors (PWRs) may include plant-specific reactor vessel underclad cracking analyses. The SRP-LR identifies that theses analyses may conform to the definition of a TLAA in 10 CFR 54.3(a) and need to be identified as TLAAs in accordance with the requirement in 10 CFR 54.21(c)(1).

In LRA Section 3.1.2.2.5 and Footnote 2 of LRA Table 4.1-1, the applicant stated that the phenomenon of reactor vessel underclad cracking is not applicable to the design of the BBS reactor vessels because the reactor vessels were not designed by B&W. Therefore, the applicant stated that the CLB does not include any analysis on reactor vessel underclad cracking that would need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1). Instead, the applicant stated that procedural protocols were implemented to control the heat input that was used to join the reactor vessel cladding to any SA-508, Class 2 low-alloy steel (LAS) components in the reactor vessels.

The staff evaluated the applicant's basis for claiming that the CLB does not include any reactor vessel underclad cracking TLAAs in SER Section 3.1.2.2.5, where the staff found that the applicant does not rely on an analysis to demonstrate that potential underclad cracks are acceptable for the period of extended operation. Instead, the staff has confirmed that the applicant relies on procedural welding heat controls (as described in the UFSAR) to preclude or underclad cracking from occurring on the BBS reactors.

<u>Lack of a Fatigue Analysis for the Main Steam Supply Lines to Turbine-Driven Auxiliary Feedwater Pumps</u>. SRP-LR Table 4.1-3 identifies that the CLB for PWRs may include fatigue analyses of the lines that provide steam to the turbine-driven auxiliary feedwater (AFW) pumps. The SRP-LR identifies that these analyses may conform to the definition of a TLAA in 10 CFR 54.3(a) and need to be identified as TLAAs in accordance with the requirement in 10 CFR 54.21(c)(1).

In LRA Table 4.1-1, the applicant stated that the CLBs for the units do not include a TLAA related to main steam supply line fatigue analyses for the AFW pumps because the units do not include steam driven AFW pumps.

The staff reviewed UFSAR Section 10.4.9.2 to evaluate the validity of the applicant's basis for its conclusion. The staff noticed that UFSAR Section 10.4.9.2 identifies that the AFW systems at BBS consist of the following two subsystems: (1) one subsystem that is designed with a motor-driven AFW pump powered by one of the emergency onsite power systems supplied from a diesel generator (DG), and (2) a second subsystem that is designed with a motor-driven AFW pump powered by a diesel engine through a gear increaser. The staff noticed that the CLBs do not rely on turbine-driven AFW pumps as a source of emergency AFW.

As such, the staff concludes that the applicant has provided an adequate basis for concluding that the CLBs do not include this type of plant-specific TLAA because the staff has confirmed the plant designs do not utilize a turbine-driven AFW system as a potential source of AFW into the secondary sides of the steam generators.

<u>Lack of a TLAA on Flow-Induced Vibrations for Reactor Vessel Internal Components</u>. SRP-LR Table 4.1-3 identifies that the CLB for PWRs may include flow-induced vibration analyses for the reactor vessel internals (RVIs) components. The SRP-LR identifies that these analyses may conform to the definition of a TLAA in 10 CFR 54.3(a) and need to be identified as TLAAs in accordance with the requirement in 10 CFR 54.21(c)(1).

In LRA Table 4.1-1, the applicant stated that the CLBs do not include any RVI flow-induced vibration analyses that conform to the definition of a TLAA in 10 CFR 54.3(a) or would need to be identified as TLAAs in accordance with the requirement in 10 CFR 54.21(c)(1). Specifically, LRA Section 4.3.5 states that the analyses associated with flow-induced vibration of the RVIs are not based on any time-dependent assumptions that would cause them to be considered a TLAA in accordance with 10 CFR 54.3(a), Criterion 3. The applicant stated that these analyses concluded that the stress ranges for the RVI components remain below the endurance limit of 10^{11} cycles on the applicable ASME fatigue curves. The applicant stated that the endurance limit is the stress range below that which the material will not experience fatigue failure. The applicant stated that, since the stress ranges remain below the endurance limit, the number of the stress range cycles is not limited over the current operating life and, therefore, the analyses are not based on any time-dependent assumptions defined by the current operating terms.

The staff reviewed the UFSAR for relevant information on flow-induced vibrations of the RVI components. The applicant's basis for evaluating the impacts of flow induced vibrations on the structural integrity and intended functions of RVI components is given in UFSAR Section 3.9. UFSAR Section 3.9.2.3 indicates that the design bases rely on previous RVI flow-induced vibration models and tests that were performed at the Indian Point Unit 2 and Trojan nuclear power plants and that these models and tests are the basis for assessing flow-induced vibrations of the RVI components at BBS.

These models and tests are summarized in the following Westinghouse technical reports (TRs):

- WCAP-8317-A, “Prediction of the Flow-Induced Vibration of Reactor Internals by Scale Model Tests,” July 1975
- WCAP-8780, “Verifications of Neutron Pad and 17 X 17 Guide Tube Designs by Preoperational Tests on the Trojan Unit 1 Plant,” May 1976

In UFSAR Section 3.9.5.2, the applicant stated that the design of the RVI components is based on the design basis loading conditions for normal operating, upset, emergency, and faulted condition transients listed on UFSAR pages 3.9-96 and 3.9-97. The staff noticed that, for the RVI components, vibratory loads (including those that would occur during postulated operational basis earthquake conditions) are listed as normal operating condition loads for the RVI components. The LRA states that the magnitude of the vibration loads for the RVI components are lower than the stress endurance limits for inducing fatigue in components. However, the staff could not determine whether this type of technical basis was established in either WCAP-8317-A or WCAP-8780. On February 26, 2014, the staff issued RAI 4.1-1, requesting that the applicant clarify whether WCAP-8317-A or WCAP-8780 establishes the basis for concluding that the RVI vibration stress loads are lower than the endurance limit for the initiation of high-cycle fatigue. If not, the staff asked to applicant to identify and justify the document in the CLB that establishes and is relied upon for this position.

The applicant responded to RAI 4.1-1 by letter dated March 28, 2014. In its response, the applicant stated that both WCAP-8317-A and WCAP-8780 establish the basis for the RVI flow-induced vibration analysis in the CLB, as discussed in UFSAR Section 3.9.2.3. The applicant stated that the initial basis for high-cycle vibratory analyses and scale model testing is provided in WCAP-8317-A and that the conclusions of WCAP-8317-A were confirmed by instrumented plant hot functional test results performed at Trojan Unit 1, as discussed in WCAP-8780.

The applicant stated that WCAP-8780 demonstrates that the stress levels due to flow-induced vibration on the RVI critical structural components were well below the endurance limits for the component materials and therefore will not experience fatigue failure.

The staff concluded that the applicant’s response demonstrates that the assessment of flow-induced vibrations in the RVI components is not within the scope of any fatigue growth parameters defined by the current operating term because (a) the vibrational stresses on the components are lower than the stress threshold for initiating fatigue cracks and (b) this demonstrates that the assessment of flow-induced vibrations in the RVI components does not involve time-limited assumptions defined by the current operating term. Therefore, based on this review, the staff finds that the applicant has provided a valid basis for concluding that the LRA does not need to include any TLAA for flow-induced vibrations because the applicant demonstrated that the assessment of flow-induced vibration does not involve time-limited assumptions defined by the current operating term such that Criterion 3 in 10 CFR 54.3(a) is not met. The staff’s concerns described in RAI 4.1-1 are resolved.

Lack of a Ductility Reduction Analysis (TLAA) for Reactor Vessel Internal (RVI) Components. SRP-LR Section 3.1.2.2.3, Subsection 3, and SRP-LR Table 4.1-3 both identify that the CLB for PWRs designed by B&W may include reduction of ductility analyses for the RVI components in the plant design. The SRP-LR identifies that the applicable analysis is given in B&W TR

BAW-2248 and may conform to the definition of a TLAA in 10 CFR 54.3(a) and need to be identified as a TLAA in accordance with the requirement in 10 CFR 54.21(c)(1).

In LRA Section 3.1.2.2.3, Subsection 3 and in LRA Table 4.1-1, the applicant stated that the CLB do not include these types of analyses. The staff's evaluation of the applicant's basis for claiming that the ductility reduction analyses in BAW-2248 is not a TLAA for the CLB is given in SER Section 3.1.2.2.3, item 3, where the staff found that the RVI components at BBS are not within the scope of the generic analysis that was evaluated in TR BAW-2248.

Lack of Metal Corrosion Allowance TLAA. SRP-LR Table 4.1-3 identifies that some plant CLB may include metal corrosion analyses for metallic components in the plant designs. The SRP-LR identifies that these analyses may conform to the definition of a TLAA in 10 CFR 54.3(a) and need to be identified as TLAAs in accordance with 10 CFR 54.21(c)(1).

In LRA Table 4.1-1, the applicant stated that the CLBs do not include any component-specific metal corrosion allowance analyses applicable to 40-year operation for BBS.

The staff reviewed the UFSAR for relevant information and noticed that it does make reference to one metal corrosion allowance. Specifically, the staff noticed that UFSAR Section 5.4.2.5.4 refers to B&W TR 222-7720-PR05, Revision 3, "Replacement Steam Generators Secondary Side Corrosion Allowance Values for Design of Analysis." However, the UFSAR does not state whether this report is being relied upon as part of the CLB or design bases for the reactor units.

By letter dated February 26, 2014, the staff issued RAI 4.1-2, requesting that the applicant clarify whether B&W TR 222-7720-PR05, Revision 3, is being relied upon for the CLB or BBS design bases. If so, the staff asked the applicant to justify why the metal corrosion allowance analysis in this report would not need to be identified as a TLAA for the secondary side of the steam generators at BBS.

The applicant responded to RAI 4.1-2 by letter dated March 28, 2014. In its response, the applicant stated that B&W TR 222-7720-PR05, Revision 3 is relied on for the CLB and that the scope of the report is used to assess general corrosion losses in the secondary side surfaces of the steam generators during normal operations and chemical cleaning activities. The applicant stated that the report includes technical bases for adding an additional metal corrosion allowance to the design thickness of these steam generator surfaces based on vendor guidance and industry experience. The applicant stated that the report is not a TLAA because it does not involve conclusions or provide the basis for drawing conclusions related to the capability of the steam generators to perform their intended functions, as defined in 10 CFR 54.4(b). The applicant concluded that the corrosion allowance basis in B&W TR No. 222-7720-PR05, Revision 3, does not meet Criterion 5 in 10 CFR 54.3(a).

The term "metal corrosion allowance" refers to and represents an additional amount of metal that was included in the original design of a metallic component beyond the amount of metal that was required to be included in the design and fabrication of the component by its design code. Licensees that previously opted to include a metal corrosion allowance in the original design of a particular metallic component did so as an additional mitigative design measure for protecting the component against loss of material effects that could be induced by potential corrosive aging mechanisms (e.g., loss of material induced by general, pitting, or crevice corrosion). SRP-LR Section 4.1 is based, in part, on assumption that, for metallic components that were designed with metal corrosion allowances, the CLB may have included time-dependent analyses that determined how much additional metal was to be included in the design and fabrication of the components. However, the staff noticed that the amount of additional metal (i.e., corrosion allowances) may also have been based on other design factors, such as operating experience (OE), simple vendor recommendations, or a design decision by the plant owner that was forwarded to the fabricator and vendor of the particular component prior to component fabrication. The staff also noticed that the amount of additional metal that was added as a design feature goes beyond the design requirements for the components, unless the corrosion allowance was specifically required to be included in the component design by the design code for the component.

The applicant's response to RAI 4.1-2 demonstrates that the additional corrosion allowance added to the wall thickness of the secondary side steam generator surfaces is based on vendor recommendations and industry experience and is not based on any analysis that would need to be identified as a TLAA, as defined by the six criteria in 10 CFR 54.3(a). The staff also noticed that this demonstrates that the additional metal corrosion allowance that was added into the design of the steam generator secondary side shell surfaces is not based on any analysis that involves conclusions or provides the basis for drawing conclusions related to the capability of the steam generators to perform their intended functions, as defined in 10 CFR 54.4(b). Therefore, based on this review, the staff finds that the applicant has provided a valid basis for concluding that the metal corrosion allowance for the steam generators does not involve a TLAA because: (a) the applicant demonstrated that the metal corrosion allowance is not based on an analysis that involves conclusions or provides the basis for drawing conclusions related to the capability of the steam generators to perform their intended functions, as defined in 10 CFR 54.4(b), and (b) this demonstrates that the assessment of the metal corrosion allowance for the steam generators does not conform to Criterion 5 in 10 CFR 54.3(a). The staff's concern described in RAI 4.1-2 is resolved.

<u>Other Potential Plant-Specific TLAAs Not Referenced in the SRP-LR</u>. The staff reviewed the information in the UFSAR to determine whether the design bases include any additional plant analyses, evaluations, calculations, or reports that would need to be identified as plant-specific TLAAs for the LRA. The staff did not identify any other plant-specific or generic analyses, evaluations, calculations, or reports that would need to be identified as plant-specific TLAAs for the LRA.

4.1.2.2 Identification of Exemptions

In LRA Section 4.1.5, the applicant identified six exemptions that were based on a TLAA and were granted in accordance with the staff's regulatory exemption acceptance requirements in 10 CFR 50.12. The staff noticed that all of these exemptions are based on the P-T limit curves that are in effect for 32 EFPY. The applicant made the following statement with respect to whether these exemptions would be applied during the period of extended operation:

> All six of the above exemptions are associated with Pressure-Temperature (P-T) limits that are applicable for 32 effective full-power years (EFPY). Based on EFPY projections described in LRA Section 4.2.1, it is expected that Byron Units 1 and 2 and Braidwood Units 1 and 2 will exceed 32 EFPY prior to the period of extended operation (PEO), thereby necessitating replacement of the P-T limit curves in accordance with 10 CFR 50, Appendix G, prior to the PEO. It is therefore anticipated that these exemptions will not be required to be in effect during PEO. If however, 32 EFPY is not reached prior to the PEO for any reason for any of the BBS units, continuation of these exemptions into the PEO, if necessary, is acceptable because the use of the exemptions as a basis for the

32 EFPY P-T limits was approved by the NRC without a limitation with respect to plant operation beyond the original license term. The above exemptions and their acceptability are not tied to or limited by the original license term.

The staff determined that the four exemptions granting permission for use of ASME Code Case N-514 and the establishment of the LTOP system setpoints are relevant to the staff's evaluation of the applicant's basis for accepting the TLAA on LTOP in accordance with 10 CFR 54.21(c)(1)(iii). The staff evaluated whether these exemptions will be needed for the period of extended operation as part of the staff's review of the UFSAR supplement for the LTOP TLAA in SER Section 4.2.6.3.

The staff also determined that the exemptions granting permission for use of ASME Code Cases N-640 and N-588, and the minimum temperature requirements methodology in WCAP-16143-P are relevant to the staff's evaluation of the applicant's basis for accepting the P-T limits TLAA in accordance with 10 CFR 54.21(c)(1)(iii). The staff evaluated whether these exemptions will be needed for the period of extended operation as part of its review of the UFSAR supplement for the P-T limits TLAA in SER Section 4.2.5.3.

The staff did not identify any other regulatory exemptions in the CLB that were granted in accordance with 10 CFR 50.12 and were based on a TLAA. Based on this review, the staff finds that the applicant has complied with the requirement in 10 CFR 54.21(c)(2) because: (a) the applicant has identified that the regulatory exemptions granted relative to compliance with the applicable requirements of 10 CFR Part 50, Appendix G, for plant P-T limits and LTOP system setpoints are exemptions that are based on a TLAA, (b) the staff has confirmed the acceptability of the applicant's basis, and (c) the staff's review of the CLB did not identify any other regulatory exemptions that were granted in accordance with 10 CFR 50.12 and based on a TLAA.

4.1.2.3 Technical Specifications—Compliance with 10 CFR 54.22

The regulation in 10 CFR 54.22 requires the applicant to identify any additions or changes to the TS that are needed for aging management during the period of extended operation. The staff determined that LRA Appendix D provides the applicant's statement on whether the LRA would need to include any TS additions or changes to comply with the requirement in 10 CFR 54.22. The applicant stated that there are no TS changes or additions that would need to be proposed for aging management of those structures, systems and components (SSCs) that were within the scope of license renewal and subject to an aging management review (AMR).

The staff reviewed the TSs to determine whether the CLB includes any TS requirements that relate to aging management of SSCs that are subject to an AMR. The staff found the following TS Administrative Control requirements may have a relationship to aging management programs (AMPs) or TLAAs that are credited for aging management:

- TS 5.5.2, "Primary Sources Outside Containment," in relation to performing visual examinations of the recirculating loops in the chemical and volume control systems, containment spray systems, residual heat removal (RHR) systems, and safety injection (SI) systems using the applicant's External Surfaces Monitoring of Mechanical Components Program (LRA Section B.2.1.23)
- TS 5.5.5, "Cyclic Component or Transient Limit," in relation to the applicant's basis for accepting fatigue-related TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) and for

managing cracking due to fatigue using the applicant's Fatigue Monitoring Program (LRA Section B.3.1.1) for components with fatigue analyses

- TS 5.5.6, "Pre-stressed Concrete Containment Tendon Surveillance Program" in relation to management of loss of material due to corrosion in the containment tendons systems and implementation of the applicant's Concrete Containment Tendon Prestress Program (LRA Section B.3.1.2)
- TS 5.5.9, "Steam Generator Program," in relation to management of cracking in the steam generator tubes and implementation of the applicant's Steam Generators Program (LRA Section B.2.1.10)
- TS 5.5.10, "Secondary Water Chemistry," in relation to management of corrosion-related aging effects in non-Class 1 components using the applicant's Water Chemistry Program (LRA Section B.2.1.2)
- TS 5.5.13, "Diesel Fuel Oil Testing Program," in relation to management of loss of material due to corrosion in the emergency diesel fuel oil storage tanks using the applicant's Fuel Oil Chemistry Program (LRA B.2.1.18)
- TS 5.5.16, "Containment Leak Rate Testing Program," in relation to the applicant's basis for managing loss of material and loss of preload in containment bolting components using the applicant's 10 CFR Part 50, Appendix J Program (LRA Section B.2.1.32)
- TS 5.6.6, "Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)," in relation to the applicant's evaluation of the TLAA on P-T Limits (LRA Section 4.2.5) and the TLAA on LTOP (LRA Section 4.2.6) in accordance with 10 CFR 54.21(c)(1)(iii), and for managing loss of fracture toughness in the reactor vessel components using the applicant's programmatic process for PTLRs as defined in the TS

With the potential exception of TS 5.6.6, the staff concluded that the applicant would not need to make any amendments to these TS requirements because the staff found that the existing wording in the TSs is sufficient to ensure adequate aging management of the SSCs. The staff also did not identify any aging management criteria in the CLB that would require the applicant to propose new TS requirements for aging management. The staff's evaluation on whether TS 5.6.6 will need to be modified in accordance the requirement in 10 CFR 54.22 is provided in SER Section 4.2.5.

4.1.3 Conclusion

Based on its review, the staff concludes that, pursuant to the requirements in 10 CFR 54.3(a) and 10 CFR 54.21(c)(1), the applicant identified those analyses in the CLB that conform to the definition of a TLAA in 10 CFR 54.3(a) and are required to be identified as TLAAs for the LRA. The staff also concludes that, pursuant to the requirements in 10 CFR 54.21(c)(2), the applicant has identified those regulatory exemptions in the CLB that were granted by the staff in accordance with the requirements in 10 CFR 50.12 and are based on a TLAA. The staff also concludes that, pursuant to the requirement in 10 CFR 54.22, and with the exception of the staff's review of the requirements in TS 5.6.6, the applicant does not need to propose any new TS requirements or change the existing TS requirements in order to manage the effects of aging during the period of extended operation.

4.2 Reactor Vessel Neutron Embrittlement Analysis

4.2.1 Neutron Fluence Projections

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 describes the applicant's TLAA for neutron fluence projections (energy (e) greater than 1 MeV) for reactor vessel beltline and extended beltline materials. The neutron fluence projections have been used as inputs to the neutron embrittlement analyses that evaluate the loss of fracture toughness resulting from neutron irradiation. Since a request for a Measurement Uncertainty Recapture (MUR) Power Uprate has been submitted to the staff, the MUR neutron flux levels were used to calculate neutron fluence for cycles occurring after the completion of the last full operating cycle prior to November 2012. These neutron fluence analysis methodologies have been approved by the staff as described in WCAP-14040-A, Revision 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," May 2004, and WCAP-16083-NP-A, Revision 0, "Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry," May 2006. These methodologies conform to Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

The applicant dispositioned the TLAA for the reactor vessel neutron fluence projections in accordance with 10 CFR 54.21(c)(1)(ii) to demonstrate that the analysis has been projected to the end of the period of extended operation.

4.2.1.2 Staff Evaluation

The staff reviewed the applicant's neutron fluence analysis for the reactor vessels, consistent with the review procedures in SRP-LR Section 4.2, which state that the applicant should identify (a) the neutron fluence for the reactor vessel at the end of the period of extended operation, (b) the staff-approved methodology used to determine the neutron fluence (or should submit the methodology for staff review), and (c) whether the methodology follows the guidance in NRC RG 1.190.

The staff noticed that LRA Table 4.2.1-1 describes the applicant's neutron fluence values (energy greater than 1 MeV) for the reactor vessel beltline and extended beltline materials at the end of the period of extended operation, consistent with the review procedures in SRP-LR Section 4.2. The applicant stated that the peak reactor vessel wall neutron fluence values for Byron Units 1 and 2 are 3.21×10^{19} n/cm^2 and 3.19×10^{19} n/cm^2, respectively, at the end of the period of extended operation, which is conservatively estimated as 57 EFPY. The applicant also stated that the peak reactor vessel wall neutron fluence values for Braidwood Station, Units 1 and 2 (Braidwood), are 3.19×10^{19} n/cm^2 and 3.16×10^{19} n/cm^2, respectively, at the end of the period of extended operation (57 EFPY).

During the AMP audit, the staff noticed that the applicant updated the maximum fluence values of Braidwood Unit 1 reactor vessel circumferential welds projected for 32 EFPY. The staff also noticed that these fluence updates were made as part of the applicant's neutron fluence TLAA for license renewal as described in WCAP-17607-NP, Revision 0, "Braidwood Station Units 1 and 2 Reactor Vessel Integrity Evaluation to Support License Renewal Time-Limited Aging Analysis," December 2012. In addition, the staff noticed that the 32-EFPY maximum fluence values of Braidwood Unit 1 reactor vessel welds, which were previously submitted to the staff as docketed information, were described in WCAP-15316, Revision 1, "Analysis of Capsule W from

Commonwealth Edison Company Braidwood Unit 1 Reactor Vessel Radiation Surveillance Program," December 1999 (ADAMS Accession No. ML003713874).

The staff noticed that the updated 32-EFPY maximum fluence values of Braidwood Unit 1 reactor vessel welds are different from those described in the docketed reactor vessel surveillance report (e.g., updated fluence of 1.69×10^{19} n/cm^2 versus the previous fluence of 1.92×10^{19} n/cm^2 for weld WR-18). In addition, the staff noticed that clarification is necessary on whether the updated fluence calculations changed the axial flux profile in a manner to reduce the axial flux peaking in the mid-core region.

The staff review considered the 32-EFPY fluence values, although they do not extend to the end of the period of extended operation, because they provide a valid comparison of the flux associated with the previous and updated calculations at the same level of exposure. Since future operation is based on a projected flux value, the fluence associated with either calculation would increase linearly beyond the current cycle. Thus any conclusions drawn from a comparison of the 32-EFPY fluence values are reasonably applicable to fluence values that cover the period of extended operation.

By letter dated February 18, 2014, the staff issued RAI 4.2.1-1 requesting that the applicant justify why the updated 32-EFPY maximum fluence values of the Braidwood Unit 1 reactor vessel welds are different from those described in the docketed reactor vessel surveillance report (i.e., WCAP-15316, Revision 1). The staff also requested that, as part of the response, the applicant clarify whether the updated fluence calculations changed the axial flux profile in a manner to reduce the axial flux peaking in the mid-core region.

In addition, the staff requested that the applicant clarify whether the updated 32-EFPY fluence values for the reactor vessel welds of Byron Units 1 and 2 and Braidwood Unit 2 are different from those reported in docketed documents similar to the Braidwood Unit 1 data. The staff further requested that, if so, the applicant justify why the updated 32-EFPY maximum fluence values are different from those reported in the docketed documents and clarify whether the updated fluence calculations reduced the axial flux peaking in the mid-core region.

In its response dated March 4, 2014, the applicant stated that the methodology used for the WCAP-15316, Revision 1, calculations followed the guidance which was documented in Draft RG DG-1053 (later issued in March 2001 as RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence") and was consistent with the NRC-approved methods in WCAP-14040-NP-A, Revision 2.

In addition, the applicant indicated that the following conservatisms were involved in the adjoint transport methodology which the applicant used in its previous fluence analysis described in WCAP-15316, Revision 1. The applicant indicated that the previous methodology does not allow cycle-to-cycle water density variations in the peripheral fuel assemblies, bypass region, or downcomer region such that water densities were chosen in the analysis to conservatively envelope actual plant operational conditions. The applicant also indicated that the methodology does not account for the flattening of the axial flux distribution that naturally occurs as a function of increasing distance from the reactor core, which results in an overestimate in the high fluence areas of the reactor vessel. The applicant further indicated that the methodology does not account for the shielding effect introduced by the former plates located at several axial elevations between the core baffle plates and the core barrel.

The applicant also stated that the methodology used in the updated neutron fluence calculations for license renewal follows the guidance of RG 1.190 and has been reviewed and approved by the staff. The applicant stated that the methodology used is consistent with WCAP-14040-A, Revision 4, and this updated methodology used a forward neutron transport approach. The applicant further indicated that the fluence analysis methodology for license renewal allows water density to be varied on a cycle-specific basis and accounts for flattening of the axial flux distribution as it propagates from the core to the reactor vessel, as well as the shielding effect of the former plates. The applicant stated that this is more representative of the actual axial neutron flux distribution and reduces the overestimation of the fluence values of the high fluence areas (i.e., mid-core region).

The applicant stated that the prior, adjoint, calculations were based on a less exact representation of the axial variations in the flux levels in the core. The calculations supporting license renewal were performed by synthesizing the three-dimensional flux from lower-dimension calculations. Although the newer calculations employ a more exact approach, RG 1.190 recommends either approach, and thus the staff determined that the flux synthesis method employed in the more recent calculations was acceptable.

The applicant's response also clarified that the updated neutron fluence calculations for license renewal accounted for several cycles of actual plant operation which were treated as projections in the previous neutron fluence calculations described in WCAP-15316, Revision 1. The applicant stated that the methodology differences and updated cycle-specific calculations for license renewal result in an axial flux profile at the pressure vessel with reduced peaking in the mid-core region compared to that in WCAP-15316, Revision 1. The applicant also stated that the reduced peaking in the mid-core region is due to the more refined analysis methodology and is more representative of actual plant operation. The applicant further stated that this refined analysis approach removed some previous dependency on over-conservatisms, and utilized more data based on actual plant operating history.

The applicant stated that there are also differences in the reported 32 EFPY fluence values for the reactor vessel welds of Byron Units 1 and 2, and Braidwood Unit 2 in the updated TLAAs for license renewal compared with those reported in docketed documents. The applicant also stated that the reasons for the differences are the same as those provided in the answer to the request above for Braidwood Unit 1.

The staff found that the applicant's response acceptable because the applicant used the staff-approved fluence analysis methodologies to calculate the neutron fluence for license renewal in accordance with RG 1.190 as described in WCAP-14040, Revision 4 and WCAP-16083-NP-A, Revision 0. The staff also confirmed that differences between previous calculations, performed in 1999, and those supporting the LRA are attributable to the following: (1) the use of cycle-specific water density data, (2) the incorporation of additional recent cycles of actual plant operation, and (3) the rendering of a more exact representation of the axial flux profile in the core, such that over-conservatism was removed from the previous neutron fluence calculation. As discussed above, both calculations were performed using methodologies that adhere to the staff's regulatory guidance; thus, the staff determined that the newer calculations are acceptable despite the differences in the specific results.

Additionally, the updated fluence calculations meet the acceptance criteria in SRP-LR Section 4.2 because the applicant projected the neutron fluence for the reactor vessels to the end of the period of extended operation using staff-approved methodologies in accordance with

RG 1.190; therefore, the applicant's TLAA for reactor vessel neutron fluence projections is acceptable.

4.2.1.3 UFSAR Supplement

LRA Section A.4.2.1 provides the UFSAR supplement summarizing the neutron fluence TLAA for the reactor vessels. The staff reviewed LRA Section A.4.2.1, consistent with the review procedures in SRP-LR Section 4.2, which state that the applicant should provide a summary description of the evaluation of the reactor vessel neutron embrittlement. Based on its review of the UFSAR supplement, the staff determines that the applicant provided an adequate summary description of its actions to address the neutron fluence analysis, as required by 10 CFR 54.21(d).

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the neutron fluence analysis for the reactor vessels has been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Upper-Shelf Energy

Section IV.A.1 to 10 CFR Part 50, Appendix G, provides the staff's requirements for demonstrating that reactor vessels in U.S. PWRs will have adequate ductility throughout their operating periods. This rule requires that reactor vessel beltline components made from ferritic materials must have a Charpy upper-shelf energy (USE) value equal to or above 75 foot-pounds (ft-lb) initially and must maintain a Charpy USE value of no less than 50 ft-lb throughout the operating period of the reactor vessel. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of USE values and describes two methods for determining USE values for reactor vessel beltline materials, depending on whether or not a given reactor vessel beltline material is represented in the plant's Reactor Vessel Surveillance program that is mandated by the requirements in Appendix H to 10 CFR Part 50. Applicants that cannot demonstrate compliance with these requirements are required to demonstrate that lower values of USE will provide adequate margins of safety from fracture equivalent to those required by Appendix G of the ASME Code Section XI.

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 describes the applicant's TLAA for the calculation of Charpy USE values for reactor vessel beltline and extended beltline components for the period of extended operation. The applicant projected the USE values using the copper contents of the materials used to fabricate the reactor vessel beltline and extended beltline components, as determined from certified material test reports (CMTRs), and the 57-EFPY fluence values for the components, as determined from the fluence values in LRA Section 4.2.1 and attenuated in accordance with Equation 3 of RG 1.99, Revision 2, the 1/4T location of the reactor vessel wall. The applicant stated that the USE values for the BBS reactor vessel beltline and extended beltline components were determined without the use of surveillance data in accordance with Regulatory Position 1.2 of NRC RG 1.99, Revision 2. In addition, the applicant stated that, where credible surveillance data was available from the Reactor Vessel Surveillance program, the projected USE values were determined by using credible USE data, as established in accordance with Regulatory Position 2.2 of RG 1.99, Revision 2. The applicant stated that USE projections without using the surveillance data resulted in lower (more conservative) USE values and that all of the projected USE values for the BBS reactor vessel beltline and extended beltline materials will remain above the 50 ft-lb requirement through the period of extended operation, as demonstrated in LRA Tables 4.2.2-1 to 4.2.2-4 for Byron Units 1 and 2 and Braidwood Units 1 and 2, respectively.

The applicant dispositioned the USE TLAA for the reactor vessel materials in accordance with 10 CFR 54.21(c)(1)(ii) to demonstrate that the analysis has been projected to the end of the period of extended operation.

4.2.2.2 Staff Evaluation

The staff reviewed the applicant's USE TLAA (LRA Section 4.2.2) and the applicant's basis for dispositioning the TLAA in accordance with 10 CFR 54.21(c)(1)(ii), consistent with the acceptance criteria in SRP-LR Section 4.2.2.1.1.2 and the review procedures in SRP-LR Section 4.2.3.1.1.2. SRP-LR Section 4.2.3.1.1.2 states that the review of the documented revised USE analysis results should be based on the review of the projected 1/4T neutron fluence projections for the reactor vessel beltline components at the end of the period of extended operation and the impacts that those fluence values will have on the USE values for the beltline components at the end of the period of extended operation. The SRP-LR section states that the staff should confirm whether the results of the USE TLAA are in compliance with USE requirements or equivalent margins analysis requirements for reactor vessel beltline components, as defined in 10 CFR Part 50, Appendix G.

RG 1.99, Revision 2 states that the Charpy USE of reactor vessel materials decreases as a function of neutron fluence and copper content. As discussed above, RG 1.99, Revision 2, also describes two methods for determining USE values for reactor vessel materials, depending on whether or not two or more credible surveillance data sets become available from the reactor in question. Regulatory Position 1.2 of RG 1.99, Revision 2, uses Figure 2 of the RG when surveillance data sets are not available. When surveillance data are available, Regulatory Position 2.2 of RG 1.99, Revision 2, is used to determine the decreases in USE by plotting the reduced plant surveillance data on Figure 2 of the RG and fitting the data with a line drawn parallel to the existing lines as the upper bound of all the data.

The applicant stated that it used Regulatory Position 1.2 of RG 1.99, Revision 2, to project the USE values to the 60-year period of extended operation for the reactor vessel beltline and extended beltline materials. The applicant also stated that, when surveillance data was available to determine the USE projections for reactor vessel materials, it listed the projected USE values determined by using Regulatory Position 2.2 of RG 1.99, Revision 2. In addition, LRA Tables 4.2.2-1 to 4.2.2-4 indicate that the applicant's projections without using the surveillance data resulted in lower (more conservative) USE values. The LRA further states that the copper content and initial USE values, which are used in the USE projections, are the data contained in the CMTRs for the reactor vessel beltline and extended beltline materials.

The staff used Position 1.2 of RG 1.99, Revision 2, to confirm the adequacy of the USE values projected at the end of the period of extended operation. Based on the analysis for all beltline and extended beltline materials, the staff confirmed that the applicant's projected USE values were determined conservatively and resulted in 60 ft-lb for the limiting material of Byron Unit 1 (intermediate shell forging-to-lower shell forging circumferential weld), 62 ft-lb for the limiting material of Byron Unit 2 (intermediate shell forging-to-lower shell forging circumferential weld, inlet nozzle-to-nozzle shell forging weld, and outlet nozzle-to-nozzle shell forging weld heat #41403), 59 ft-lb for the limiting material of Braidwood Unit 1 (inlet nozzle-to-nozzle shell forging weld WF-598 and outlet nozzle-to-nozzle shell forging weld WF-598), and 62 ft-lb for the limiting material of Braidwood Unit 2 (intermediate shell forging-to-lower shell forging circumferential weld). Thus, the staff finds that the BBS beltline and extended beltline materials have projected USE values at 1/4T greater than 50 ft-lb in compliance with Appendix G to 10 CFR Part 50.

On the basis of its review, the staff finds the applicant demonstrated pursuant to 10 CFR 54.21(c)(1)(ii), that the USE analysis for the reactor vessels has been projected to the end of the period of extended operation. Additionally, the staff finds that the applicant's USE analysis meets the acceptance criteria in SRP-LR Section 4.2.2.1.1.2 because the applicant's analysis adequately demonstrates that the projected USE values for the reactor vessel beltline and extended beltline material at the end of the period of extended operation are not less than 50 ft-lb in compliance with the requirements of 10 CFR Part 50, Appendix G; therefore, the applicant's USE TLAA is acceptable.

4.2.2.3 UFSAR Supplement

LRA Section A.4.2.2 provides the UFSAR supplement summarizing the USE TLAA for the reactor vessels. The staff reviewed LRA Section A.4.2.2, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the applicant should provide a summary description of the evaluation of the reactor vessel neutron embrittlement TLAA and provide information equivalent to SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, the staff determines that the applicant provided an adequate summary description of its actions to address USE, as required by 10 CFR 54.21(d).

4.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE for the reactor vessels has been projected to the end of the period of extended operation and meets the acceptance criteria of Appendix G to 10 CFR Part 50. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the USE TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.3 Pressurized Thermal Shock

Section 50.61 of 10 CFR establishes fracture toughness requirements for the protection of PWRs against postulated pressurized thermal shock (PTS) events. Such events, which are caused by severe overcooling concurrent with or followed by significant pressure, can lead to brittle fracture of the reactor pressure vessel (RPV). As such, the PTS requirements are part of the staff's regulatory framework for assuring that the structural integrity of the RPV is adequately maintained. To demonstrate adequate protection against PTS events, 10 CFR 50.61 requires an assessment of the reference temperature for each RPV beltline material. This reference temperature is a measure of the brittleness of the material, and it must be based on the projected effects of neutron irradiation over the period of plant operation. In accordance with 10 CFR 50.61(b), the PTS assessment must be updated upon a request for a change in the expiration date for operation of the facility. Therefore, the PTS assessment must be updated for license renewal.

The requirements of 10 CFR 50.61 prescribe an equation that must be used to calculate the reference temperature for the PTS assessment (RT_{PTS}). This equation is:

$$RT_{PTS} = RT_{NDT(U)} + \Delta RT_{NDT} + M$$

The $RT_{NDT(U)}$ term is the reference temperature for the RPV material in the preservice or unirradiated condition, as determined in accordance with the procedures of ASME Code, Section III, Paragraph NB-2331, or other NRC-approved methods. The ΔRT_{NDT} term is the mean value of the transition temperature shift for the material due to irradiation. This term is a function of the chemistry factor, which is based on the copper and nickel content of the material, and the best estimate neutron fluence at the clad-base-metal interface on the inside surface of the RPV at the location where the material in question receives the highest fluence for the period of service in question. The term M is a margin to account for uncertainties in the values of $RT_{NDT(U)}$, the copper and nickel content of the material, and the fluence and calculation procedures. The methods for determining the ΔRT_{NDT} and margin term values are described in 10 CFR 50.61(c)(1). Provisions for incorporating credible surveillance test data into the ΔRT_{NDT} estimate are described in 10 CFR 50.61(c)(2).

The results of the RT_{PTS} assessment, as calculated per 10 CFR 50.61(c), must be less than or equal to the PTS screening criteria specified in 10 CFR 50.61(b)(2). The screening criterion for RPV plates, forgings, and axial weld materials is 270 °F (132 °C), and the criterion for circumferential weld materials is 300 °F (149 °C). If the results of the RT_{PTS} assessment show that the PTS screening criteria cannot be met, then 10 CFR 50.61 provides licensees with certain actions that can be taken to permit continued plant operation, including (a) implementation of a flux reduction program to avoid exceeding the screening criteria, (b) submission of a safety analysis to determine what, if any, modifications to equipment, systems, and operation are necessary to prevent potential failure of the RPV as a result of postulated PTS events, or (c) implementation of a thermal annealing treatment of the RPV beltline materials to recover their fracture toughness.

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 describes the applicant's evaluation of the PTS TLAA. The LRA states that the applicant used the guidance in RG 1.99, Revision 2, to calculate the RT_{PTS} values for the RPV beltline materials. The LRA states that the applicant used RG 1.99, Revision 2, Regulatory Position C.1 for the calculations involving materials that did not have credible surveillance data, whereas Regulatory Position C.2 was used for the calculations involving materials that had two or more sets of credible surveillance data. Inputs to the calculations included the copper and nickel contents of the beltline materials and the 57 EFPY fluence values projected through the end of the period of extended operation. LRA Tables 4.2.3-1 to 4.2.3-4 provide the results of the applicant's updated RT_{PTS} calculations. Among all four of the BBS units, the applicant projects the limiting (or highest) RT_{PTS} value for the forging materials to be 114 °F (46 °C) at 57 EFPY. According to the LRA, this value corresponds to the Byron Unit 1 intermediate shell forging based on the use of noncredible surveillance data. The applicant projects the limiting RT_{PTS} value for the circumferential weld materials to be 124 °F (51 °C) at 57 EFPY. According to the LRA, this value corresponds to the Byron Unit 2 intermediate shell forging-to-lower shell forging circumferential weld (Heat No. 442002) based on the use of credible surveillance data. The applicant dispositioned the TLAA for the PTS assessments in accordance with 10 CFR 54.21(c)(1)(ii) to demonstrate that the analyses have been projected to the end of the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the PTS assessments and the corresponding disposition of 10 CFR 54.21(c)(1)(ii) consistent with the review procedures in SRP-LR Section 4.2.3.1.2.2. Accordingly, the staff reviewed the TLAA for compliance with the requirements of 10 CFR 50.61, which involved an evaluation of the results of the applicant's revised RT_{PTS} calculations based on the projected neutron fluence at the end of the period of extended operation (57 EFPY).

The requirements of 10 CFR 50.61 apply to the RPV beltline materials. The staff considers the beltline to include any RPV material projected to receive a fluence of at least $1{\times}10^{17}$ n/cm^2 (E greater than 1 MeV). In the past, this definition has limited the beltline to components in the shell course region directly surrounding the effective height of the active reactor core. However, with extended operation, some RPV components outside this region may also experience fluence levels of at least $1{\times}10^{17}$ n/cm^2 (E greater than 1 MeV) and, therefore, are also evaluated as part of the beltline. The term "beltline materials" is used to refer to the group of materials that surround the effective height of the active reactor core, and the term "extended beltline materials" is used to refer to the group of remaining materials that receive a fluence of at least $1{\times}10^{17}$ n/cm^2. The applicant's PTS assessments include both beltline and extended beltline materials due to the projected fluence levels at the end of the period of extended operation. At BBS, the extended beltline includes certain inlet and outlet nozzles and welds.

The staff reviewed the applicant's methodology for calculating the RT_{PTS} values. The staff determined that the methodology was acceptable because it followed the requirements of 10 CFR 50.61(c).

The staff also reviewed the adequacy of the applicant's values for $RT_{NDT(U)}$, which is the first term in the equation for calculating RT_{PTS}. The staff compared the $RT_{NDT(U)}$ values in LRA Tables 4.2.3-1 to 4.2.3-4 against the $RT_{NDT(U)}$ values in two CLB sources. One source was the applicant's revised PTLRs for 32 EFPY, which it reported to the staff in 2007 per the requirements of TSs Section 5.6.6. The other source was the UFSAR. Based on this comparison, the staff determined that the $RT_{NDT(U)}$ values in the LRA are consistent with the $RT_{NDT(U)}$ values from both CLB sources, with the exception of the value for the Braidwood, Unit 2 nozzle shell forging-to-intermediate shell forging circumferential weld seam, which is made from Heat No. H4498. For this material, the staff found that LRA Table 4.2.3-4 identifies $RT_{NDT(U)}$ to be −25 °F (−32 °C); however, UFSAR Table 5.3-10 identifies $RT_{NDT(U)}$ to be −30 °F. By letter dated March 11, 2014, the staff issued RAI 4.2.3-1, requesting the applicant to identify and substantiate the correct $RT_{NDT(U)}$ value for this material and explain the discrepancy between the LRA and the UFSAR.

The applicant responded to RAI 4.2.3-1 by letter dated April 8, 2014. The applicant explained that the discrepancy between the two $RT_{NDT(U)}$ values for this material is a historical issue. According to the applicant, a review of the CMTR indicates that the difference in the $RT_{NDT(U)}$ values is due to different interpretations of the raw Charpy test data by separate vendors. The applicant also stated that both values have been used in past PTS analyses submitted on the docket. For example, the −30 °F $RT_{NDT(U)}$ value was used in analyses submitted by letters dated July 12, 1990, and August 8, 1994, and the −25 °F value was used in analyses submitted by letters dated September 3, 1998, and February 28, 2014. The applicant stated that it considers the −25 °F value of $RT_{NDT(U)}$ to be the CLB for Braidwood, Unit 2.

The staff reviewed the letters referenced in the applicant's response to RAI 4.2.3-1 and confirmed that both $RT_{NDT(U)}$ values have been used in past PTS analyses submitted on the docket. However, the staff finds the applicant's use of the −25 °F value of $RT_{NDT(U)}$ for the PTS assessment in the LRA acceptable because it is based on the CMTR data. In addition, the use of this value is acceptable because it produces a more conservative RT_{PTS} value for the Braidwood, Unit 2 nozzle shell forging-to-intermediate shell forging circumferential weld seam (made from Heat No. H4498), as compared to use of the −30 °F value of $RT_{NDT(U)}$. With resolution of this RAI, the staff determined that the applicant used appropriate $RT_{NDT(U)}$ values for its RT_{PTS} calculations. The staff's concern described in RAI 4.2.3-1 is resolved.

The staff also reviewed the adequacy of the applicant's values for ΔRT_{NDT} and margin, which are the remaining terms in the equation for calculating RT_{PTS}. The ΔRT_{NDT} term is the product of a function involving the best estimate neutron fluence and a chemistry factor. As discussed in SER Section 4.2.1, the staff found that the applicant's neutron fluence projections for the period of extended operation are acceptable. In accordance with the requirements of 10 CFR 50.61, the chemistry factor depends on whether the material for a given RPV component is represented in the surveillance program and, if so, whether the surveillance data for that material is credible. When there is no credible surveillance data, the chemistry factor must be based on the copper and nickel content of the material. In these cases, the staff compared the copper and nickel content values from LRA Tables 4.2.3-1 to 4.2.3-4 against the values in the PTLRs for 32 EFPY and the UFSAR. The staff found that all values were in agreement. The staff also determined that the applicant selected appropriate chemistry factors based on the copper and nickel content of the materials, as required by 10 CFR 50.61(c)(1)(iv)(A). When there is credible surveillance data, the chemistry factor must be based on measured values of ΔRT_{NDT} and fluence, as obtained through implementation of the surveillance program. In these cases, since no additional surveillance tests have been conducted since the PTLRs for 32 EFPY were submitted, the staff compared the chemistry factors in LRA Tables 4.2.3-1 to 4.2.3-4 against the material-specific chemistry factors in the PTLRs. The staff found that the values in the LRA were consistent with the values in the PTLRs and, therefore, acceptable. For the margin terms, the staff determined that the applicant used appropriate inputs based on the type of material (i.e., weld or base metal) and whether the material is represented in the surveillance program and whether the surveillance data for the material is credible. The staff determined that the margin terms were calculated consistent with the requirements of 10 CFR 50.61(c)(1)(iii) for components not represented by credible surveillance data and 10 CFR 50.61(c)(2)(iii) for components represented by credible surveillance data. Based on this review, the staff determined that the applicant used appropriate ΔRT_{NDT} and margin values for its RT_{PTS} calculations.

After confirming that the applicant used appropriate inputs to determine the $RT_{NDT(U)}$, ΔRT_{NDT}, and margin terms, the staff used the applicant's values for these terms to independently calculate RT_{PTS} for each RPV beltline material. In all cases the staff's calculations were in agreement with the results reported by the applicant; therefore, the staff determined that the applicant's RT_{PTS} calculations are acceptable. The staff then compared the results against the PTS screening criteria in 10 CFR 50.61(b)(2). Of the four units, the highest calculated RT_{PTS} value for RPV plates, forgings, and axial weld materials is 114 °F (46 °C), which is well below the 270 °F (132 °C) screening criterion. The highest calculated RT_{PTS} value for the circumferential weld materials is 124 °F (51 °C), which is also well below the 300 °F (149 °C) screening criterion. Based on these results, the staff determined that the applicant demonstrated sufficient margins of protection against postulated PTS events for the period of extended operation.

The staff finds that the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the PTS assessments for the RPVs have been projected to the end of the period of extended operation. Additionally, the PTS assessments meet the acceptance criteria in SRP-LR Section 4.2.2.1.2.2 because the applicant appropriately recalculated the assessments to consider the period of extended operation, in accordance with the requirements of 10 CFR 50.61. Based on this evaluation, the staff finds that the results of the updated PTS assessments are less than the screening criteria in 10 CFR 50.61(b)(2) for the period of extended operation.

4.2.3.3 UFSAR Supplement

LRA Section A.4.2.3 provides the UFSAR supplement summarizing the PTS assessments for the RPVs. The staff reviewed LRA Section A.4.2.3 consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the applicant should provide a summary description of the reactor vessel neutron embrittlement TLAA and provide information equivalent to the examples in SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.2.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the PTS TLAA assessments, as required by 10 CFR 54.21(d).

4.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the PTS assessments for the RPVs have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Adjusted Reference Temperature

The guidance in RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” provides the staff’s recommended position for calculating the adjusted reference temperature values (ART or RT_{NDT} values) of those RPV components that are within the scope of the P-T limit evaluations, which are required to be calculated in accordance with the regulation in 10 CFR Part 50, Appendix G, “Fracture Toughness Requirements.” These ART values are based on an evaluation of the neutron fluence values of the RPV components, as attenuated from the RPV inside wetted interface to depths at one-quarter and three-quarters of the RPV wall thickness (i.e., 1/4T and 3/4T locations in the RPVs). The ART values are inputs to the plant P-T limit curves, which are required to be included either in the plant-specific TS limiting conditions for operation (LCO) or in a PTLR that is managed in accordance with specific requirements in the Administrative Controls Section of the TSs.

In accordance with Westinghouse Non-Proprietary Class 3 Report No. WCAP-14040-NP-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves” (current NRC-approved version is Revision 4 of the WCAP), and RG 1.99, Revision 2, ART values (RT_{NDT} values) are calculated in accordance with Equation 1 below:

$$\text{ART or } RT_{NDT} = \text{Initial } RT_{NDT} + \Delta RT_{NDT} + M \quad \text{(Equation 1)}$$

In this equation, the initial RT_{NDT} is the unirradiated ART value or unirradiated RT_{NDT} value for the component, as derived in accordance with the requirements in Section III of the ASME

Boiler and Pressure Vessel (B&PV) Code (ASME Code Section III), Paragraph NB-2331. ΔRT_{NDT} is the shift in the RT_{NDT} value that is induced by neutron irradiation, and M is a margin term that is added into the calculation to account for uncertainties in the calculation methods.

In accordance with RG 1.99, Revision 2, the ΔRT_{NDT} value is calculated in accordance with Equation 2 below:

$$\Delta RT_{NDT} = CF \text{ x } f^{(0.28 - 0.1 \text{ x } \log f)} \quad \text{(Equation 2)}$$

In this equation, f is the neutron fluence of the component (in units of 10^{19} n/cm^2 [E > 1.0 MeV]) and CF is a chemistry factor. The neutron fluence is evaluated for the specific location of interest (e.g., 1/4T or 3/4T), as described below. The chemistry factor is dependent on the Cu and Ni alloying contents of the component's material and determined from either the CF tables in the RG (i.e., Regulatory Position 1.1 in the RG) or from credible RPV material surveillance test data that are obtained through implementation of the applicant's Reactor Vessel Surveillance Program (i.e., Regulatory Position 2.1 in the RG).

RG 1.99, Revision 2, includes a method to calculate the neutron fluence for any location inside the RPV wall thickness. The RG states that the neutron fluence at any depth in RPV wall is calculated in accordance with the following neutron fluence attenuation equation (i.e., Equation 3 below):

$$f = f_{surf}\, e^{(-0.24^{*}x)} \quad \text{(Equation 3)}$$

In this equation, f_{surf} (in units of 10^{19} n/cm^2 [E > 1.0 MeV]) is the calculated value of the neutron fluence at the inside wetted surface of the vessel, and x (in inches) is the depth into the vessel wall, as measured from the vessel inner (wetted) surface. Alternatively, the RG establishes that, if displacements per atom (dpa) calculations are used for the neutron fluence analysis, the ratio of dpa at the depth in question to dpa at the inner surface may be substituted for the exponential attenuation factor in Equation 3. Since the neutron fluence values for the components increase with time, it is the neutron fluence values that establish the time-dependency of these calculations.

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 describes the applicant's TLAA for the ART calculations. The applicant stated that the ART value of the limiting RPV beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. The applicant stated that 10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel, and that under this rule, the initial RT_{NDT} is evaluated in accordance with the procedures in ASME Code Section III, Paragraph NB-2331.

The applicant also stated that, because accumulated neutron fluence increases the ART for a given RPV beltline component beyond its initial unirradiated value, the shift in the RT_{NDT} (ΔRT_{NDT}) must be evaluated as part of the ART calculations. The applicant also stated that, since the ΔRT_{NDT} values are a function of the neutron fluence values that were assessed for the initial 40-year licensed operating period, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 60 years of extended operation. The applicant stated that, since the calculations for the ART TLAA have been updated to project them to the end of the period of extended operation (i.e., to 57 EFPY), the TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify that the ART analyses for Byron Units 1 and 2 and Braidwood Units 1 and 2 have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). The staff also reviewed LRA Section 4.2.4, consistent with the review procedures in SRP-LR Section 4.7.3.1.2, which state that the documented results of the revised analyses are reviewed to verify that their periods of evaluation are extended such that they are valid for the period of extended operation. The SRP-LR also states that the applicable analysis technique can be the one that is in effect in the plant's CLB at the time of filing of the renewal application.

The staff determined that the applicant uses the methods of analysis in ASME Section XI, Appendix G to generate the P-T limit curves for its reactor units. The staff also noticed that updates of P-T limit curves for the reactor units are performed in accordance with TS 5.6.6, which governs implementation of the applicant's PTLR process and requires updates of the P-T limits to be performed in accordance with specific NRC-approved methodologies referenced by the TS requirements, including the methodology in Westinghouse Topical Report (TR) WCAP-14040-NP-A. The staff further noticed that the methodology in WCAP-14040, Revision 4, as mandated by TS 5.6.6, requires the ART calculations (i.e., RT_{NDT} calculations) to be performed based on an assessment of both the 1/4T and 3/4T neutron fluence values for the RPV beltline and extended beltline components. However, the staff observed that LRA Section 4.2.4 did not include any ART values that were based on the 3/4T fluence values for RPV beltline and extended beltline components at 57 EFPY.

By letter dated April 8, 2014, the staff issued RAI 4.2.4-1/RAI A.4.2.4-1, requesting resolution of these matters. In RAI 4.2.4-1/RAI A.4.2.4-1, Part 1, the staff asked the applicant to amend LRA Section 4.2.4 to provide the ART tables and values that are based on an assessment of the 3/4T neutron fluence values for the RPV beltline and extended beltline components at 57 EFPY. In RAI 4.2.4-1/RAI A.4.2.4-1, Part 2, the staff asked the applicant to provide a basis for dispositioning the ART TLAA in terms of 10 CFR 54.21(c)(1)(ii), given that these values are used to evaluate the P-T limits for the period of extended operation, which are being accepted in accordance with 10 CFR 54.21(c)(1)(iii) (see SER Section 4.2.5). Otherwise, the staff asked the applicant to revise the LRA to disposition the TLAA for projected ART values in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant responded to RAI 4.2.4-1/A.4.2.4-1, Parts 1 and 2, in a letter dated May 6, 2014. In it response to RAI 4.2.4-1/A.4.2.4-1, Part 1, the applicant stated that it amended its basis for accepting the TLAA to be in accordance with 10 CFR 54.21(c)(1)(iii). The applicant also stated that the "limiting 1/4T and 3/4T ART values will continue to be provided with the PTLR report to maintain the P-T limits in accordance with the TS requirements during the period of extended operation, as presented in LRA Section 4.2.5, Pressure-Temperature Limits." In its response to RAI 4.2.4-1/A.4.2.4-1, Part 2, the applicant further stated that it amended LRA Table 4.1-2, LRA Section 4.2.4, and LRA Section A.4.2.4 (UFSAR supplement) to reflect that the ART TLAA is accepted in accordance with 10 CFR 54.21(c)(1)(iii).

The staff noticed that the applicant's responses to RAI 4.2.4-1/A.4.2.4-1, Parts 1 and 2, included an amendment to the LRA to accept the TLAA on ART in accordance with 10 CFR 54.21(c)(1)(iii). The staff finds that the applicant has provided an acceptable basis for accepting the TLAA on ART in accordance with 10 CFR 54.21(c)(1)(iii) because the applicant will manage the TLAA through implementation of TS 5.6.6 and the applicant's basis is consistent with SRP-LR Section 4.2.2.1.3.3. Therefore, the issues identified in RAI 4.2.4-1/A.4.2.4-1 are resolved.

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the ART analyses for the reactor vessels will be adequately managed through implementation of the PTLR requirements in TS 5.6.6 during the period of extended operation.

4.2.4.3 UFSAR Supplement

LRA Section A.4.2.4 provides the UFSAR supplement summarizing the basis for accepting the TLAA on ART in accordance with the criterion in 10 CFR 54.21(c)(1)(ii). SRP-LR Section 4.2.3 does not include any recommended guidelines for reviewing TLAAs on ART that are accepted in accordance with the criterion in 10 CFR 54.21(c)(1)(ii). Therefore, the staff reviewed LRA Section A.4.2.4, consistent with the review procedures in SRP-LR Section 4.7.3.1.2, which state that the staff should review the documented results of the revised analyses to verify that their period of evaluation is extended, such that they are valid for the period of extended operation (e.g., 60 years).

The staff found that LRA Section A.4.2.4 stated that "57-EFPY 1/4T fluence values were used to compute ART values for BBS beltline and extended beltline materials in accordance with RG 1.99, Revision 2 requirements." The staff concluded that this basis is not consistent with the requirements in TS 5.6.6 because: (a) the TS provisions require that the calculations of ART values will need to be based, in part, on the methodology that is given in WCAP-14040-NP-A, and (b) WCAP-14040-NP-A, Revision 4, would require that ART calculations would need to include both 1/4T and 3/4T ART calculations for the RPV beltline and extended beltline components at 57 EFPY.

By letter dated April 8, 2014, as part of RAI 4.2.4-1/A.4.2.4-1, Parts 1 and 2, the staff asked the applicant to amend the UFSAR supplement to indicate that both the 57-EFPY 1/4T and 3/4T fluence values were used to compute ART values for BBS beltline and extended beltline materials in accordance with methodology in WCAP-14040-NP, as required by TS 5.6.6. The applicant responded to RAI 4.2.4-1/A.4.2.4-1, Parts 1 and 2, in a letter dated May 6, 2014. In its responses to these parts of the RAI, the applicant t amended the UFSAR supplement to change the basis for accepting the TLAA on ART from 10 CFR 54.21(c)(1)(ii) to 10 CFR 54.21(c)(1)(iii). The applicant also amended the UFSAR supplement to state that the "limiting 1/4T and 3/4T ART values will continue to be provided with the PTLR report to maintain the P-T limits in accordance with the Technical Specification requirements during the period of extended operation, as presented in LRA Section 4.2.5, Pressure-Temperature Limits."

The staff determined that the applicant's basis is consistent with TS 5.6.6 for implementing the applicant's PTLR process. The staff also confirmed that the applicant made the applicable changes to the UFSAR supplement in LRA Section A.4.2.4 on the basis for accepting this TLAA in accordance with 10 CFR 54.21(c)(1)(iii). The issues raised in RAI 4.2.4-1/A.4.2.4-1 are resolved with respect to the contents of LRA UFSAR Section 4.2.4 and the bases for accepting this TLAA in accordance with 10 CFR 54.21(c)(1)(iii).

The staff also noticed UFSAR supplement A.4.2.4 references a 200 °F (90 °C) value that is discussed in Section C.3 of RG 1.99, Revision 2. The staff noticed that the applicant's basis implies that the 200 °F value was included in the RG section to place a maximum limit on the calculation of 1/4T ART values. However, the staff noticed that Section C.3 of RG 1.99, Revision 2, relates to bases for RPV material selection when choosing the ferritic steel materials that would be used to fabricate the RPVs of newly constructed plants. In addition, the staff noticed that the 200 °F value referenced in Section C.3 of the RG serves only as a recommended ART basis for establishing and limiting the copper (Cu) contents of ferritic steel materials that are procured and used for fabrication of the RPVs in new plants. The staff further noticed that the referenced 200 °F value is not used to place a maximum limit on the calculation of 1/4T ART values once the RPV is fabricated and the plant is operated.

By letter dated April 8, 2014, the staff issued RAI A.4.2.4-2, requesting that the applicant amend LRA Section A.4.2.4 to be consistent with the 200 °F value basis that is referenced in Section C.3 of RG 1.99, Revision 2, or provide a technical basis for the applicant's statement as written. Otherwise, the RAI requested that the applicant amend LRA Section A.4.2.4 to delete that statement from the UFSAR supplement section.

The applicant responded to RAI A.4.2.4-2 in a letter dated May 6, 2014. In it response, the applicant stated that it was amending LRA Section 4.2.4 and A.4.2.4 to delete the 200 °F value basis that is referenced to Section C.3 of RG 1.99, Revision 2, in LRA Section A.4.2.4. The staff reviewed the applicant's letter of May 6, 2014, and found that the applicant made acceptable changes to LRA Section A.4.2.4 because RG 1.99, Revision 2, does not place any upper bound limit on the ART values that are calculated for the RPV beltline and extended beltline components. The issue raised in RAI A.4.2.4-2 is resolved.

Based on its review of the UFSAR supplement, as amended in the applicant's letter of May 6, 2014, the staff finds LRA Section A.4.2.4 meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.2, and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of the TLAA on ART and its actions for using this TLAA as part of the bases for managing loss of fracture toughness due to neutron irradiation embrittlement of the ferritic steel components in the RPVs, as required by 10 CFR 54.21(d).

4.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the ART analyses for the reactor vessels will be adequately managed by the applicant's implementation of TS 5.6.6 and the PTLR process activities during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 Pressure-Temperature Limits

The regulation in 10 CFR 50.36 requires the P-T limits for a licensed nuclear plant to be established and controlled by the TS for the facility. This is accomplished by either including the P-T limits in the LCOs of the TS, or else, if approved in a previously issued license amendment, in a PTLR that is within the scope of and is administratively controlled by the Administrative Controls Section of the TS. The regulation in 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements," establishes the requirements for performing calculations of these P-T limits and requires that the P-T limits for the facility must be at least as conservative as those that would be generated if the methods of analysis in Appendix G of the ASME Code Section XI were used to generate the P-T limits.

For ferritic components in the beltline region of the RPV, the regulation requires the P-T limits to account for the effects of neutron irradiation. Therefore, the P-T limits are based, in part, on a function of a time-dependent neutron fluence parameter and must be updated periodically to remain valid for continued service of the facility. In addition, the regulation in 10 CFR Part 50, Appendix G requires that the generation of P-T limits must take into account the relevant neutron dosimetry data and Charpy-impact data that are generated through implementation of the applicant's 10 CFR Part 50, Appendix H, RPV surveillance program, as described in LRA AMP B.1.35.

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.5 describes the applicant's TLAA on P-T limits. The applicant stated that the P-T limits for Byron Units 1 and 2 and Braidwood Units 1 and 2 are required to be calculated in accordance with the requirements of 10 CFR Part 50, Appendix G. The applicant also stated that the P-T limits identify the maximum allowable operating pressure of the RCS as a function of reactor coolant temperature. The applicant further stated that, as the reactor vessel is exposed to increased neutron irradiation, its fracture toughness is reduced.

In addition, the applicant stated that the regulation in 10 CFR Part 50, Appendix G, therefore, requires impacts of the anticipated reactor vessel fluence to be taken into account for P-T limit assessments. In addition, the applicant stated that the current P-T limits are based upon neutron fluence projections for a 40-year licensed operating period. The applicant further stated that, since the P-T limits were originally based upon the 40-year assumption, the P-T limits for the reactor units satisfy the criteria of 10 CFR 54.3(a) and have been identified as a TLAA.

In LRA Section 4.2.5, the applicant summarized its basis for controlling and updating the plant-specific P-T limits for the Byron and Braidwood units in accordance with the Administrative Control requirements in TS 5.6.6 and the applicant's PTLR process. The applicant also provided its basis for using TS 5.6.6 and the PTLR process to accept the TLAA on P-T limits in accordance with 10 CFR 54.21(c)(1)(iii).

4.2.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA on P-T limits and the proposed disposition of the TLAA in accordance with 10 CFR 54.21(c)(1)(iii) in order to: (a) verify whether the impact of loss of fracture toughness due to neutron irradiation embrittlement on the intended reactor coolant pressure boundary (RCPB) function of the RPVs would be adequately managed during the period of extended operation, and (b) determine whether the applicant's implementation of the requirements in TS 5.6.6 and its PTLR process would provide an acceptable basis for managing this aging effect during the period of extended operation.

The staff determined that SRP-LR Section 4.2.3.1.3.3 describes the staff's acceptance criteria for approving a TLAA on P-T limits in accordance with 10 CFR 54.21(c)(1)(iii). For CLB with approved PTLRs, SRP-LR Section 4.2.2.1.3.3 states that updated P-T limits for the period of extended operation must be available prior to entering the period of extended operation and that the requirements for implementing the PTLR process in the Administrative Controls Section of the TSs can be considered adequate AMPs or activities for the period of extended operation. The staff found that the applicant's basis for the disposition of the TLAA on P-T limits in accordance with 10 CFR 54.21(c)(1)(iii) was consistent with the acceptance criteria in SRP-LR Section 4.2.2.1.3.3, with the exception of the following matters that needed additional clarification by the applicant.

The staff noticed the applicant's basis for performing future updates of the P-T limits for Byron Units 1 and 2 and Braidwood Units 1 and 2 lie in the administrative control requirements in TS 5.6.6 and the applicant's procedures for implementing its PTLR process. The staff also noticed that the specifications in TS 5.6.6 require the applicant to perform updates of the P-T limit curves in accordance with the following NRC-approved methodologies:

- the methodologies referenced in the NRC letter of January 21, 1998, "Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, Acceptance of Referencing Pressure Temperature Limits Report," which included but are not limited to the methodology in Westinghouse nonproprietary report WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigation System Setpoints and RCS Heatup and Cooldown Limit Curves"
- the methodologies referenced in the NRC letter of August 8, 2001, "Issuance of Exemption from the Requirements of 10 CFR 50.60 and Appendix G for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2"
- the methodology in Westinghouse Proprietary Class 2 Report WCAP-16143, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2," November 2003, which was approved in 2006 as an acceptable exemption from the requirements in 10 CFR Part 50, Appendix G, for performing P-T limit evaluations

In addition, the staff found that the regulation in 10 CFR Part 50 Appendix G, "Fracture Toughness Requirements," establishes the minimum fracture toughness requirements that must be met for RCPB components made from ferritic steels. The staff noticed that the rule requires the calculation of P-T limits to be based on an evaluation of all ferritic steel components that are located in the RPV, including those that are located outside of the beltline region of the RPV. The staff also noticed that, for the ferritic RPV components that are located in the beltline region of the vessel, the rule requires that assessment of P-T limits (and in particular, the RT_{NDT} values that are used in the P-T limit calculations) must account for the effects of neutron irradiation, including the results of the RPV surveillance capsule withdrawal program, as required to be implemented in accordance with 10 CFR Part 50, Appendix H.

The staff found that both LRA Section 4.2.5 and UFSAR supplement in LRA Section A.4.2.5 stated that, in order to meet these Appendix G requirements, the "analysis for the P-T curves will consider locations outside of the beltline such as nozzles, penetrations and other discontinuities (i.e., RPV nonbeltline components) to determine if more restrictive P-T limits are required than would be determined by considering only the reactor vessel beltline materials." However, 10 CFR 54.22 requires the applicant to include in its LRA any TS additions or changes that are necessary to manage the effects of aging during the period of extended operation. Section 54.22 also requires that the justification for such TS changes or additions be included in the application. In addition, Generic Letter (GL) 96-03, "Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits," establishes the criteria that must be included in the Administrative Controls of the TSs and the applicant's PTLR processes as approved by the staff. The criteria in GL 96-03 are based on the requirement that the applicant's methodologies for generating P-T limits, as invoked by the TS requirements for PTLRs, comply with 10 CFR Part 50, Appendix G, unless applicable exemptions from the Appendix G requirements are requested in accordance with 10 CFR 50.60(b) and approved by the staff in accordance with 10 CFR 50.12.

Based on this review, it was not evident to the staff why the assessment of RPV nonbeltline components had been addressed as an enhancement in the UFSAR supplement (LRA Section A.4.2.5) when, in accordance with GL 96-03, this type of assessment should be included as part of the methodologies that were approved as P-T limit methodologies for TS 5.6.6. The staff also noticed that, in 1991 for Braidwood Unit 2 and in 2010 for Byron Unit 2, the applicant modified the RPV closure flange configurations by either removing or cutting one stud from the RPV closure flange assembly or by leaving one stud untensioned when operating the reactor. However, the staff noticed that the methods of analysis in WCAP-16143, as invoked by TS 5.6.6, were based on the original plant design configuration for the RPV closure flange assemblies, and were not on the modified RPV closure flange assembly designs with one stud not fully tensioned. As a result, the staff determined that the applicant would need to justify why a change to TS 5.6.6, Part b, or to the methodologies invoked by TS 5.6.6, Part b, would not need to be processed as part of the LRA, as mandated in accordance with the 10 CFR 54.22 requirements.

By letter dated April 8, 2014, the staff issued RAI 4.2.5-1/RAI A.4.2.5-1, Parts 1 through 3, requesting resolution of these issues. In RAI 4.2.5-1/RAI A.4.2.5-1, Part 1, the staff asked the applicant to clarify how the applicant will assess RPV nonbeltline structural discontinuities for their impact on the future P-T limits for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii) and how this assessment will be factored into the update of the PTLRs that will be performed in accordance TS 5.6.6, Part c. The staff also asked the applicant to justify why this assessment of the RPV nonbeltline structural discontinuities is proposed as an enhancement in LRA Section A.4.2.5 in contrast with the NRC position established in GL 96-03 that this type of assessment be performed in accordance with the 10 CFR Part 50, Appendix G requirements and be included within the scope of at least one of the P-T limit methodologies that are invoked by TS 5.6.6, Part b.

In RAI 4.2.5-1/RAI A.4.2.5-1, Part 2, the staff asked the applicant to justify why the current methodologies specified in TS 5.6.6 and the plant procedures for implementing the PTLR process would be valid for updating the P-T limits for the period of extended operation, given that the P-T limits minimum temperature requirement methodology in WCAP-16143 is not consistent with the current design configurations of the RPV closure flange assemblies at Byron Unit 2 and at Braidwood Unit 2.

In RAI 4.2.5-1/RAI A.4.2.5-1, Part 3, the staff requested the applicant to consider its responses to Request Parts 1 and 2 of the RAI, and based on these responses, to clarify whether changes to TS 5.6.6 need to be proposed in accordance with the requirements in 10 CFR 54.22 and whether changes to the methodologies invoked by TS 5.6.6 need to be proposed for the LRA. The staff also requested that the applicant amend LRA Sections 4.2.5 and A.4.2.5 if either TS 5.6.6 or the methodologies invoked by TS 5.6.6 would need to be amended in accordance with the 10 CFR 54.22 requirements.

The applicant responded to RAI 4.2.5-1/RAI A.4.2.5-1, Parts 1 – 3, in a letter dated May 6, 2014 (ML14126A338). In its response to RAI 4.2.5-1/RAI A.4.2.5-1, Part 1, the applicant stated that the assessment of RPV nonbeltline structural discontinuities for their impact on future P-T limits will be performed in accordance with 10 CFR 54.21(c)(1)(iii) and will be factored into the update of the PTLRs that will be submitted to the staff in accordance with TS 5.6.6, Part c. The applicant also stated that the revisions to the P-T limits beyond the current P-T limits will continue to consider the positions and criteria discussed in GL 96-03, which would have this type of assessment performed in accordance with 10 CFR Part 50, Appendix G requirements. The applicant further stated that the LRA is amended to provide this further clarification of the consideration of the 10 CFR 50, Appendix G requirements, which recognizes the ASME Section XI, Appendix G limits as an acceptable approach for analyzing and ensuring that a sufficient margin of safety is established in the P-T limits that will be calculated in accordance the applicable TS requirements. In addition, the applicant stated that the compliance with the requirements in ASME Section XI, Appendix G is included within the scope of TS 5.6.6, Part b, since ASME Section XI, Appendix G-based methodologies are used and these methodologies have been approved by the staff. The applicant stated that, since TS 5.6.6, Part b, implements the ASME Section XI, Appendix G requirements, and since the ASME Section XI, Appendix G includes the consideration of the assessment of RPV nonbeltline structural discontinuities, no enhancement was intended by the LRA statement.

The applicant stated that the recent issuance of the draft Regulatory Issue Summary (RIS) 2014-XX, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components" (ADAMS Package Accession No. ML14028A179, Memo Accession No. ML14027A577, and *Federal Register* notice Accession No. ML14027A668), also addresses the need to consider the nonbeltline structural discontinuities. The applicant stated that, with the issuance of the final RIS, further clarification will be provided on the expectations for future PTLR submittals on this subject. The applicant further stated that after the issuance of the final RIS, and with PTLRs that will be required to be updated in accordance with TS 5.6.6 for the period of extended operation, Exelon will, in accordance with TS requirements, provide PTLRs which sufficiently address all ferritic materials of pressure-retaining components of the RCPB, including an assessment of the impacts that structural discontinuities in the RPVs and increased neutron fluence accumulation will have on the P-T limits for the period of extended operation.

The staff noticed that TS 5.6.6 requires, in part, that WCAP-14040-NP-A will be used to generate the P-T limits that will be calculated for the period of extended operation in accordance with the TLAA acceptance requirement in 10 CFR 54.21(c)(1)(iii). The staff also noticed that the methodology for calculating P-T limits in WCAP-14040-NP-A is based on compliance with the requirements in 10 CFR Part 50, Appendix G, and Appendix G of the ASME Code Section XI, and with the recommended criteria in RG 1.99, Revision 2. The staff also confirmed that the applicant amended LRA Section 4.2.5 to state that the "PTLR revision necessary to extend the P-T limits into the period of extended operation will consider all ferritic materials of pressure-retaining components of the RCPB including the impact of structural discontinuities, and address the impact of neutron fluence accumulation in accordance with the requirements of 10 CFR 50, Appendix G." Thus, the staff determined that, based on the amendment of this LRA, the applicant has adequately demonstrated that implementation of the P-T limit methodology requirements in both the TS 5.6.6 and 10 CFR Part 50, Appendix G, requirements will ensure that the process for updating the P-T limits for the facilities will include an assessment of the impacts that RPV structural discontinuities and accumulated neutron fluence will have on the P-T limits that will be generated for the period of extended operation. The staff finds this basis to be acceptable because the applicant demonstrated that its P-T limits will be calculated in accordance with methodologies required by TS 5.6.6 and the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii). The issue in RAI 4.2.5-1/A.4.2.5-1, Part 1, is resolved.

In its response to RAI 4.2.5-1/RAI A.4.2.5-1, Part 2, the applicant stated that the current P-T limit methodologies, as required by TS 5.6.6, and the plant procedures for implementing the PTLR process, will be valid for updating the P-T limits that will be generated for the period of extended operation. The applicant stated that, given that the P-T limits minimum temperature requirement methodology in WCAP-16143-P is not based on the configurations of current RPV closure flange assemblies at Byron Unit 2 and Braidwood Unit 2, additional commitments have been made in Exelon's response to Notice of Violation dated December 13, 2013, to take corrective steps for revising the methodology in WCAP-16143-P and to reflect the Braidwood Unit 2 configuration of 53 RPV head bolts. In addition, the applicant stated that the revision of WCAP-16143-P will include the 53 RPV head bolt configuration at Byron Unit 2 and that the revision of WCAP-16143-P will bring the methodology in agreement with the current configuration. The applicant stated that, in regard to the period of extended operation, a commitment was made to restore the configuration for Byron Unit 2 and Braidwood Unit 2 RPV closure flange assemblies to that analyzed in WCAP-16143-P prior to the period of extended operation, and that this commitment was made in Exelon's response to NRC RAI B.2.1.3-2, as provided in letter dated December 19, 2013. The applicant further stated that the implementation of these commitments will maintain the current TS 5.6.6 methodologies and plant procedures for implementing the PTLR process valid for the current operating period and the period of extended operation.

The staff noticed that requirements in TS 5.6.6 reference WCAP-16143-P as one of the required methodologies that will be used for updating the P-T limits for the reactor units and that WCAP-16143-P provides an alternative, NRC-approved method for establishing those minimum temperature requirements that need to be within the scope of the P-T limit calculations. The staff noticed that the methodology in WCAP-16143-P for establishing these minimum temperature requirements was approved as an exemption from the minimum temperature requirements that are stated in 10 CFR Part 50, Appendix G, and that the applicant identified this exemption (see LRA page 4.1-10) as an exemption for the LRA that was granted in accordance with provisions in 10 CFR 50.12 and based on a TLAA.

The staff also confirmed that, in letter dated December 19, 2013, the applicant amended LRA Table A.5 to include Commitment No. 47, in which the applicant committed to the repair of the RPV closure flange assembly at Braidwood Unit 2 at least 6 months prior to entering the period of extended operation for the unit, and Commitment No. 48, in which the applicant committed to the repair of the RPV closure flange assembly at Byron Unit 2 at least 6 months prior to entering the period of extended operation for the unit. The staff also noticed that these activities to repair the RPV closure flange assemblies at Byron Unit 2 and Braidwood Unit 2 will make the flange assembly configurations consistent with those analyzed in WCAP-16143-P. As discussed in SER Section 3.0.3.2.2, the applicant updated the status of Commitment No. 47 by reporting that the Byron Unit 2 partially stuck stud No. 11 was removed, and that an inspection showed no damage on the stud or flange hole threads. In addition, in order to ensure that the Braidwood Unit 2 inoperable stud location (No. 35) is restored so that all 54 reactor head closure studs are tensioned during the period of extended operation, the staff has proposed incorporating applicant's Commitment No. 48 into a license condition. Therefore, based on these considerations, the staff finds the technical bases in WCAP-16143-P will remain valid as an alternative methodology for establishing the minimum temperature requirements that need to be within the scope of the P-T limit calculations for the period of extended operation, which will be calculated in accordance with the TS 5.6.6 requirements and the methodologies invoked by those requirements. The issue in RAI 4.2.5-1/A.4.2.5-1, Part 2, is resolved.

In its response to RAI 4.2.5-1/RAI A.4.2.5-1, Part 3, the applicant stated that, based on the responses to Request Parts 1 and 2 above, there are no changes to TS 5.6.6 or to the methodologies invoked by TS 5.6.6 for the LRA in accordance with the requirement in 10 CFR 54.22. Based on the applicant's amendments of the LRA, as clarified in the applicant's responses to RAI 4.2.5-1/RAI A.4.2.5-1, Parts 1 and 2, the staff finds that the applicant demonstrated that proposed changes to TS 5.6.6 do not need to be addressed pursuant to 10 CFR 54.22 because the applicant has committed to the repair of the Byron Unit 2 and

Braidwood Unit 2 RPV closure flange assemblies (as evaluated immediately above) such that design configuration of the RPVs for these units will be consistent with the assumptions and alternative methods of analysis in proprietary report WCAP-16143-P, as invoked for use by PTLR process requirements in TS 5.6.6. The issue in RAI 4.2.5-1/A.4.2.5-1, Part 3, is resolved.

The staff also reviewed the applicant's P-T limit basis against applicable information contained in the UFSAR. UFSAR Section 5.3.2.1 states that the RPV "surveillance program withdrawal schedule is contained in Table 4.1 of the PTLR document for each unit, respectively." UFSAR Section 5.3.2.1 also states that "[c]hanges to the withdrawal schedule may be made as part of an update to the PTLR under the provisions of 10 CFR 50.59."

The staff found that GL 96-03 states that P-T limit changes and the LTOP system setpoint changes could be processed through a licensee's 10 CFR 50.59 and PTLR processes, as long at the PTLR methodologies approved in the Administrative Controls Section of the TSs are used to make the changes to the P-T limits and to the low pressure overpressure protection (LTOP) system setpoint values (see SER Section 4.2.6). Because Appendix H to 10 CFR Part 50 requires that proposed changes to the RPV surveillance program withdrawal schedules for the units be submitted to the staff for review and approval, withdrawal schedule changes are not subject to the provisions of 10 CFR 50.59. As a result, the staff noticed that the position in GL 96-03 does not relieve a licensee from compliance with the requirement in 10 CFR Part 50, Appendix H, to submit applicant's proposed changes to the RPV surveillance program withdrawal schedule for NRC review and approval.

By letter dated April 8, 2014, the staff issued RAI 4.2.5-2, requesting that the applicant provide its justification for stating that future "[c]hanges to the withdrawal schedule may be made as part of an update to the PTLR under the provisions of 10 CFR 50.59." The applicant responded to RAI 4.2.5-2, in a letter dated May 6, 2014 (ML14126A338).

In its response, the applicant stated that it agrees that the subject statement in UFSAR Section 5.3.2.1 needs to be corrected. The applicant also stated that the referenced statement in UFSAR Section 5.3.2.1 is inconsistent with both UFSAR Section 5.3.1.6 and the statement in the NRC SER of January 21, 1998 (ADAMS Legacy Library Accession Number 9802040391), which approved the PTLRs for the reactor units. The applicant also stated it was acceptable to control the RPV surveillance capsule withdrawal schedule in PTLRs because changes to the schedules would need to be subjected to the reporting and review and approval requirements in 10 CFR Part 50, Appendix H. The applicant stated that this issue has been entered into the corrective action program (CAP) for revising the UFSAR to correct the inconsistency between UFSAR Section 5.3.2.1 and 5.3.1.6.

The staff concluded that the applicant's response to RAI 4.5.2-2 demonstrates that the applicant is aware that any future changes to the RPV surveillance capsule withdrawal schedules are required to be submitted to the staff for review and approval in accordance with the 10 CFR Part 50, Appendix H, requirements and that any changes to the capsule withdrawal schedules cannot be implemented without prior NRC approval. The staff also noticed that the applicant will make the appropriate amendments of UFSAR Section 5.3.2.1 through implementation of the applicant's process for amending the UFSAR, which is subject to the requirements in 10 CFR 50.71(e). The issue in RAI 4.2.5-2 is resolved.

On the basis of the staff's review described above, the staff finds that the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the applicant's P-T limits will be adequately managed during the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.3 because, consistent with the SRP-LR recommendations, the applicant adequately demonstrated that it will use the requirements of TS 5.6.6 and the methodologies invoked by TS 5.6.6 to update the P-T limits for the period of extended operation.

4.2.5.3 UFSAR Supplement

LRA Section A.4.2.5, "Pressure-Temperature Limits," provides the applicant's UFSAR supplement summary description for the TLAA on P-T limits. The staff reviewed LRA Section A.4.2.5 against the UFSAR acceptance criteria in SRP-LR Section 4.2.2.2, which state that the summary description for the TLAA on P-T limits should contain appropriate information that demonstrates why the TLAA may be accepted in accordance with one of the three acceptance criteria for accepting TLAAs in 10 CFR 54.21(c)(1)(i), (ii) or (iii). The staff also performed its review consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the NRC reviewer should verify that the applicant provided sufficient information in its UFSAR supplement that includes a summary description of the evaluation of the TLAA on P-T limits and why the TLAA on P-T limits is acceptable in accordance with 10 CFR 54.21(c)(1)(i), (ii) or (iii). The SRP-LR also states that SRP-LR Table 4.2-1 contains an example of an acceptable UFSAR supplement for this TLAA and that the NRC reviewer should verify that the applicant's UFSAR supplement provides information that is at least as comprehensive as the UFSAR supplement example that is provided for this type of TLAA in SRP-LR Table 4.2-1.

The staff noticed the UFSAR supplement for the TLAA on P-T limits provided an adequate summary of the basis for accepting the TLAA with the requirement in 10 CFR 54.21(c)(1)(iii) and for accepting the basis that implementation of TS 5.6.6 and methodologies invoked by the TS requirements will serve as an acceptable basis for calculating the P-T limit curves that will be needed for the period of extended operation. However, the staff did request further demonstration that the methodologies used for the generation of the P-T limits would appropriately assess all ferritic components in the RPV and that WCAP-16143-P will remain an acceptable alternative minimum temperature requirement methodology for the P-T limits that will be calculated for the period of extended operation. As discussed in Section 4.2.5.2 of this SER, the staff addressed these issues in RAI 4.2.5-1/RAI A.4.2.5-1, Parts 1 - 3, which were issued to the applicant in a letter dated April 8, 2014.

As discussed in SER Section 4.2.5.2, the staff evaluated the applicant's response letters dated May 6, 2014, and January 23, 2015, which include the applicant's responses to this RAI, an LRA amendment of UFSAR supplement Section A.4.2.5, and inclusion of Commitment Nos. 47 (reported as complete) and 48 in UFSAR supplement Table A.5. The staff concluded that the applicant's responses to this RAI, the amendment of the UFSAR supplement in LRA Section A.4.2.5, the completion of Commitment No. 47, and the inclusion of Commitment No. 48 as a license condition, provide reasonable assurance that the methodologies that are required by TS 5.6.6 and will be used to update the P-T limits for the reactor units will assess the impacts that RPV structural discontinuities and increasing neutron fluence will have on the P-T limits for the period of extended operation. The staff also concluded that the applicant's responses to the RAI and the activities of Commitment Nos. 47 (reported as complete) and 48 (incorporated into a license condition) resolved the issue regarding the acceptability of WCAP-16143-P as a basis for calculating the P-T limits for the period of extended operation. The staff also finds that the applicant's responses to the RAI will ensure that the methodology in WCAP-16143-P will remain as a valid, NRC-approved alternative basis for establishing the minimum temperature requirements that will be factored into the P-T limit calculations because the the applicant will repair the RPV closure flange assemblies at Braidwood Unit 2 and Byron Unit 2 in order to ensure that the design configuration for the assemblies will be in conformance with the assumptions and methodology in WCAP-16143-P. Therefore, based on this review, the staff determined that the applicant's responses to RAI 4.2.5-1/RAI A.4.2.5-1, Parts 1 to 3 in the May 6, 2014, letter, the updated response in the letter dated January 23, 2015, and incorporation of Commitment No. 48 into a license condition, provide an acceptable basis for demonstrating that the implementation of the TS 5.6.6 requirements and the applicant's PTLR process may be used to accept this TLAA in accordance with 10 CFR 54.21(c)(1)(iii) and to generate those P-T limits that will be needed to support plant operations during the period of extended operation. The issues in RAI 4.2.5-1/RAI A.4.2.5-1, Parts 1 to 3, are resolved with respect to the acceptability of LRA Section A.4.2.5.

Based on its review of the UFSAR supplement, as amended in the applicant's letter of May 6, 2014, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.3, and, therefore, is acceptable. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the TLAA on P-T limits, as required by 10 CFR 54.21(d).

4.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the TLAA on P-T limits will be adequately managed by the TS 5.6.6 requirements and the PTLR process activities during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.6 Low Temperature Overpressure Protection Analyses

4.2.6.1 Summary of Technical Information in the Application

LRA Section 4.2.6 describes the applicant's TLAA for the LTOP system setpoints. The LRA states that the LTOP system is required by TS Section 3.4.12 to prevent the pressure in the RCS from exceeding the maximum pressure established in the P-T limits during certain design basis transients. The LTOP system provides the overpressure protection automatically through the use of either: (a) two power-operated relief valves in the pressurizer, (b) two RHR suction relief valves, or (c) a combination of one power-operated relief valve and one RHR suction relief valve. The LRA states that the LTOP system setpoints will need to be re-evaluated because they are based on the current P-T limits, all of which will need to be updated for the period of extended operation. The LRA states that the applicant will use the Reactor Vessel Surveillance program, described in LRA Section B.2.1.19, to re-evaluate the LTOP system setpoints and submit the results to the staff. The applicant dispositioned the TLAA for the LTOP system setpoints in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of loss of fracture toughness on the intended functions will be adequately managed by the Reactor Vessel Surveillance program for the period of extended operation.

4.2.6.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the LTOP system setpoints and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the staff is to review the applicant's aging management activities to verify that the effects of aging on the intended functions will be adequately managed consistent with the CLB for the period of extended operation.

TS Section 5.6.6 requires the applicant to report the LTOP system setpoints in a PTLR for each reactor vessel fluence period and for any revision or supplement thereto. By letter dated March 27, 2014, the applicant submitted the current PTLRs for Byron, Units 1 and 2, which are applicable for 32 EFPY and 30.5 EFPY, respectively. By letter dated May 9, 2014, the applicant submitted the current PTLRs for Braidwood, Units 1 and 2, which are applicable for 32 EFPY. Since the fluence periods covered by the current PTLRs do not encompass the entire period of extended operation (projected to be 57 EFPY), the applicant will need to re-evaluate the LTOP system setpoints to account for the loss of fracture toughness of the reactor vessels by neutron embrittlement. LRA Section 4.2.6 states that the applicant re-evaluate the LTOP system setpoints and report the results to the staff as part of the Reactor Vessel Surveillance program.

The staff reviewed the adequacy of the Reactor Vessel Surveillance program for re-evaluating and reporting the LTOP system setpoints for the period of extended operation. Based on the description provided in LRA Section B.2.1.19, the staff determined that the program is primarily for condition monitoring because it generates material and dosimetry data for monitoring irradiation embrittlement of the reactor vessels. While this program will provide certain input data needed to generate the LTOP system setpoints, the staff determined that the program does not include the specific analytical methods and processes that are needed to establish, document, and report the LTOP system setpoints as required by the CLB. SRP-LR Section 4.2.2.1.3.3 states that, for P-T limits that will be maintained through the period of extended operation, the use of a PTLR process included in the administrative controls section of the TSs is considered to be an adequate aging management activity for meeting the requirements of 10 CFR 54.21(c)(1)(iii). TS Section 5.6.6 describes the PTLR process for BBS. In addition to providing the requirements for updating the P-T limits, this section also provides the analytical methods and reporting requirements for updating the LTOP system setpoints. By letter dated April 8, 2014, the staff issued RAI 4.2.6-1 requesting that the applicant explain why it did not plan to use the analytical methods and processes required by TS Section 5.6.6 to establish, document, and report the updated LTOP system setpoints that will be needed for the period of extended operation. The staff also requested that the applicant identify and explain the TS changes or additions needed per the requirements of 10 CFR 54.22 if the applicant planned to use an approach different from the requirements of TS Section 5.6.6.

The applicant responded to RAI 4.2.6-1 by letter dated May 6, 2014. In its response, the applicant acknowledged that TS Section 5.6.6 identifies the analytical methods that must be used to establish the LTOP system setpoints. The applicant indicated that these methods are described in an NRC letter dated January 21, 1998. The applicant also acknowledged that TS Section 5.6.6 requires the LTOP system setpoints to be included in the PTLRs, which must be reported to the staff when updated. The applicant stated that these activities constitute its PTLR process and, instead of using the Reactor Vessel Surveillance program, the applicant stated that it will use the PTLR process to generate and submit the appropriate analyses for the LTOP system setpoints for the period of extended operation.

The staff reviewed the applicant's response to RAI 4.2.6-1 and determined that the applicant will follow its PTLR process in accordance with the requirements of TS Section 5.6.6 to re-evaluate, establish, and report the LTOP system setpoints that will be needed for the period of extended operation. The staff finds this process acceptable because it is comparable to the process for updating the P-T limits, as described in the acceptance criteria in SRP-LR Section 4.2.2.1.3.3. These requirements will ensure that the applicant appropriately accounts for the effects of loss of fracture toughness of the reactor vessels when the LTOP system setpoints are re-evaluated. The staff's concern described in RAI 4.2.6-1 is resolved.

Pursuant to 10 CFR 54.21(c)(2), the applicant must also provide a list of all plant-specific exemptions granted under 10 CFR 50.12 that are in effect and based on a TLAA. The applicant must justify continuation of these exemptions for the period of extended operation. LRA Section 4.1.5 identifies four exemptions that are in effect and based on the TLAA for the LTOP system setpoints. According to the LRA, the staff granted these exemptions on July 13, 1995; November 29, 1996; December 12, 1997; and January 16, 1998. The LRA states that the exemptions permit the applicant to establish the LTOP system setpoints such that the LTOP systems will limit the maximum pressure in the reactor vessels to 110 percent of the pressure determined to satisfy the requirements of ASME Code, Section XI, Appendix G. As to the justification for continuation of these exemptions, LRA Section 4.1.5 states that they are all associated with the current P-T limits. Based on its neutron fluence projections, the applicant expects that BBS will exceed the terms of applicability of these P-T limits prior to the period of extended operation. As such, new P-T limits will be required for the period of extended operation. However, the LRA states that the exemptions related to the LTOP system setpoints will not be needed because the applicant will develop the new setpoints per the requirements of 10 CFR Part 50, Appendix G. The LRA further states that, if the BBS units do not exceed the terms of applicability of their current P-T limits, then continuation of the exemptions is justified because the prior NRC approvals are not limited to the current license term.

The staff reviewed the applicant's justification for continuation of the exemptions related to the TLAA for the LTOP system setpoints. TS Section 5.6.6 specifies the analytical methods that the applicant must use to establish the LTOP system setpoints. One of the required analytical methods is identified as "NRC letter dated January 21, 1998, 'Byron Station Units 1 and 2, and Braidwood Station, Units 1 and 2, Acceptance for Referencing of Pressure Temperature Limits Report.'" The staff confirmed that this document incorporates the four letters listed in LRA Section 4.1.5 and that these letters approve the exemptions related to the LTOP system setpoints. Collectively, the exemptions permit the applicant to use ASME Code Case N-514, "Low Temperature Overpressure Protection, Section XI, Division 1" as the basis for determining the LTOP system setpoints.

Approved code cases are generally incorporated into later editions and addenda of the ASME Code, the staff reviewed the history of ASME Code Case N-514 to determine if its content is included in the most-recent edition and addenda endorsed by the staff. Per RG 1.147, Revision 16, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1," dated October 2010, the staff had unconditionally approved ASME Code Case N-514; however, the ASME annulled the code case after incorporating the requirements into ASME Code, Section XI. The staff reviewed a copy of ASME Code Case N-514 and found that it requires the LTOP system to operate in accordance with these two requirements:

(1) The system must be effective at coolant temperatures less than 200 °F or at coolant temperatures corresponding to a reactor vessel metal temperature that is less than RT_{NDT} plus 50 °F (10 °C), whichever is greater.

(2) The system must limit the maximum pressure in the vessel to 110 percent of the pressure determined to satisfy the requirements of ASME Code, Section XI, Appendix G.

Per 10 CFR 50.55a(b)(2), the staff currently endorses up to the 2007 Edition with the 2008 Addenda of ASME Code, Section XI. The staff reviewed this edition and addenda and determined that ASME Code, Section XI, Paragraph G-2215 incorporates the first requirement of ASME Code Case N-514 related to the temperature at which the LTOP system must be effective. However, the staff found that ASME Code, Section XI, does not incorporate the second requirement from ASME Code Case N-514 related to the maximum pressure limit. Specifically, ASME Code, Section XI, Paragraph G-2215 requires the LTOP system to limit the pressure in the reactor vessel to 100 percent of the pressure determined to satisfy the requirements of ASME Code, Section XI, Appendix G. This limit is more restrictive than the limit allowed by ASME Code Case N-514.

After further research, the staff found that the limit currently specified in ASME Code, Section XI, Paragraph G-2215 is based on the now-annulled ASME Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves, Section XI, Division 1." The staff reviewed a copy of ASME Code Case N-640 and determined that it essentially removes the second requirement of ASME Code Case N-514 related to the maximum pressure limit. In addition, the staff determined that the applicant must follow ASME Code Case N-640 because it is one of the other analytical methods required by TS Section 5.6.6 for establishing the P-T limits and LTOP system setpoints. In particular, TS Section 5.6.6 identifies this method as "NRC letter dated August 8, 2001, 'Issuance of Exemption from the requirements of 10 CFR 50.60 and Appendix G, for Byron Station, Units 1 and 2 and Braidwood Station, Units 1 and 2.'"

The staff determined that TS Section 5.6.6 requires the applicant to follow both ASME Code Cases N-514 and N-640. Therefore, the analytical methods for determining the LTOP system setpoints are equivalent to the current provisions of ASME Code, Section XI, Appendix G, as required by 10 CFR Part 50, Appendix G. Based on the equivalency with current NRC requirements, the staff determined that continuation of the exemption related to ASME Code Case N514 is acceptable for the period of extended operation. This exemption is justified for both: (a) the future LTOP system setpoints, which the applicant will be required to develop according to the analytical methods in TS 5.6.6, and (b) the current LTOP system setpoints, which were also developed according to the analytical methods in TS 5.6.6, as stated in the methodologies described in the current PTLRs.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of loss of fracture toughness on the intended functions of the reactor vessels will be adequately managed for the period of extended operation. This demonstration also meets the acceptance criteria in SRP-LR Section 4.7.2.1.

4.2.6.3 UFSAR Supplement

LRA Section A.4.2.6 provides the UFSAR supplement summarizing the TLAA for the LTOP system setpoints. The staff reviewed LRA Section A.4.2.6 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the applicant is to provide a summary description for its evaluation of each TLAA. The SRP-LR also states that the summary description should contain information on the disposition of the TLAA for the period of extended operation and be appropriate such that later changes can be controlled by 10 CFR 50.59. By letter dated May 6, 2014, the applicant amended LRA Section A.4.2.6 to reflect its response to RAI 4.2.6-1. Accordingly, the applicant revised the summary description to state that it will use its PTLR process to demonstrate compliance with 10 CFR 54.21(c)(1)(iii) for the TLAA. Based on its review of the UFSAR supplement, as amended by letter dated May 6, 2014, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.7.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address updates to the LTOP system setpoints, as required by 10 CFR 54.21(d).

4.2.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the LTOP system setpoints will be adequately managed for the period of extended operation in accordance with the PTLR process required by TS 5.6.6. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

LRA Section 4.3 provides the applicant's assessment of metal fatigue as a TLAA for license renewal.

4.3.1 Transient Inputs to Fatigue Analyses

4.3.1.1 Summary of Technical Information

LRA Section 4.3.1 includes Tables 4.3.1-1 through 4.3.1-6, which list the 60-year projections of transients applicable to BBS, Units 1 and 2.

LRA Section 4.3.1 states that ASME Code Section III, Class 1 fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the specifications. The LRA states that each BBS component designed in accordance with ASME Code Section III requiring a fatigue analysis was analyzed and shown to have a cumulative usage factor (CUF) less than the allowable design limit of 1.0. Some ASME Code Section III Class 2 heat exchangers at BBS were evaluated for fatigue similar to Class 1 components using transient inputs from LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The LRA states that since the fatigue analyses are based upon a number of cycles postulated to bound 40 years of service, projection of the transients' cycles through the period of extended operation is required as an input to demonstrate that the analyses remain valid.

In order to determine that the analyses remain valid for 60 years of service, the applicant reviewed the fatigued monitoring data to determine the number of cumulative cycles of each transient type that has occurred during past plant operation. The LRA provided details of the projection methodology to determine the 60-year projected number of cycles.

The LRA states that an evaluation was performed to determine if the severity of the actual plant transients that have occurred during past operations remains bounded by the transient severity assumed in each transient definition in the design specification. This was done to determine whether the past cycles were appropriately characterized during the fatigue monitoring activities. The administrative and operating procedures were also reviewed to assess the effectiveness of the design transient cycle counting and to validate the cyclic assumptions.

LRA Section 4.3.1 states that, since the transients have been projected to the end of the period of extended operation, this section has been dispositioned in accordance with 10 CFR 54.21(c)(1)(ii). The LRA states the transients are used as inputs in the metal fatigue TLAA evaluations in the remainder of LRA Section 4.3.

4.3.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1 to confirm that the transients that are significant fatigue contributors are monitored to ensure that the applicant's fatigue evaluations remain valid. The staff also reviewed the methodology used by the applicant to obtain the 60-year projections. The staff noticed that the applicant will use its Fatigue Monitoring program to track and monitor the transients included in LRA Section 4.3.1. The staff's evaluation of the applicant's Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

LRA Tables 4.3.1-2 and 4.3.1-5 provides the baseline cycles, 60-year projected cycles, and CLB cycle limit for Transient 6, "Letdown Flow Shutoff Prompt Return to Service." The LRA states that the baseline cycles for Byron Unit 2 and the projected 60-year projected cycles for all four units exceed the CLB cycle limit for the transient. The LRA states that the transient was redefined as four differential temperature range transients. The LRA further states that the number of baseline and 60-year projected cycles for each of the differential temperature range transients were determined and a reanalysis was performed for the bounding location, which confirmed that the CUF will remain below 1.0. The staff noted that the applicant did not provide a technical basis for redefining the original transient definition to four new transients.

By letter dated February 26, 2014, the staff issued RAI 4.3.1-1 requesting that the applicant provide the four redefined differential temperature range transients and include the transient definitions, baseline cycle counts, 60-year projected cycle counts, and CLB cycle limits for each redefined transient. The applicant was also requested to describe and justify the basis for redefining the original transient definition and confirm that its Fatigue Monitoring program will monitor the redefined transient cycles and severities and will require corrective action prior to exceeding design limits.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.1-1. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that each unit has both a normal and an alternate charging line. The applicant stated that these lines are used alternately each refueling outage to distribute the fatigue effects of system transients between the two lines. The applicant stated that the charging nozzle is the limiting component on each line and was evaluated for environmentally assisted fatigue (EAF). The applicant noted that the baseline cycle count for this transient represents the total cycles from both lines, not cycles per nozzle. The applicant provided the four redefined transients for Transient 6, along with the baseline cycles, the projected cycles, and the number of cycles used in the EAF evaluations.

The applicant stated that actual operating transients were less severe than the design transients based on comparison of actual plant-specific transient data against the original design transients. The applicant stated that its review of the plant data showed that a large number of transient cycles associated with flow isolation design transients with temperature changes that were below the temperature changes associated with the design transient, but the total number of transient cycles exceeded the number assumed in the original design analysis. The applicant stated that the cycles were counted within various bounding temperature difference ranges for each unit. The applicant stated that it established the CLB cycle limits, which included the effects of EAF, based on Byron, Unit 2, data because it had the maximum projected number of cycles in each temperature difference range. The applicant stated that the cycle limit distribution was applied to all four units. The applicant confirmed that the Fatigue Monitoring program will track and monitor these transient cycles and severities and will require corrective action prior to exceeding design limits.

The staff finds the response acceptable because the updated transients were redefined based on actual plant parameters and the applicant provided the baseline cycle counts, projected 60-year counts, and CLB cycle limits for the four redefined transients and updated the LRA to reflect them. The applicant also confirmed that the Fatigue Monitoring program will monitor these transients. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24. The staff's concern in RAI 4.3.1-1 is resolved.

LRA Tables 4.3.1-1 and 4.3.1-4 state that Transient 16, "Recovery of Main Feedwater Flow After Isolation (Units 1 only)," is applicable to the Unit 1 steam generators for both Byron and Braidwood. The LRA further states that Transient 16 is not evaluated because cycles associated with switching between main and auxiliary feedwater flow are implicit in the cycles counted for other RCS transients. The staff noticed that the LRA does not specify which other RCS transients will be monitored to account for Transient 16. It was also unclear to the staff why Transient 16 was applicable to Byron, Unit 1, and Braidwood, Unit 1, only.

By letter dated February 26, 2014, the staff issued RAI 4.3.1-3 requesting the applicant to identify which RCS transients will be monitored to account for Transient 16 and justify that monitoring these other RCS transients will be adequate so that Transient 16 will not need to be monitored through the period of extended operation. The applicant was also requested to clarify and justify why Transient 16 is applicable to Byron, Unit 1, and Braidwood, Unit 1, only.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.1-3. The applicant provided the set of upset condition transients for Byron, Unit 1 that occur before Transient 16 occurs. The applicant stated these transients are captured in LRA Tables 4.3.1-1 and 4.3.1-4, which are monitored by the Fatigue Monitoring program through the period of extended operation. The applicant further stated that Transient 16 is only included in the design basis and CLB for the replacement steam generators (RSGs) installed at Byron, Unit 1, and Braidwood Unit 1, as indicated in the RSG design transient specifications. The applicant stated that the Byron, Unit 2, and Braidwood, Unit 2, steam generator design analysis or CLB do not include this transient.

The staff finds the applicant's response acceptable because the applicant provided the transients that account for the cycles for Transient 16. The staff confirmed that these transients are included in the LRA tables that will be monitored by the Fatigue Monitoring program. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24. The applicant further provided an adequate basis why Transient 16 is applicable only to Byron, Unit 1, and Braidwood, Unit 1, steam generators. The staff's concerns in RAI 4.3.1-3 are resolved.

LRA Tables 4.3.1-1 and 4.3.1-4 state that Transient 14, "Sampling Line and Nozzles Transients," will not be monitored. The LRA states that chemistry samples are taken at a much lower frequency than that which was assumed in the design, resulting in fewer cycles. The LRA further states that samples are no longer taken from the RCS as specified in the design, and are taken instead from the letdown system. The LRA states that samples from the letdown system result in lower temperature differences and lower transient severity. It was unclear to the staff how the information provided in the LRA regarding the lower frequency and differences support the basis for not monitoring Transient 14.

By letter dated February 26, 2014, the staff issued RAI 4.3.1-4 requesting the applicant to provide the comparison of frequencies and temperature differences at which chemistry samples are taken from the letdown system instead of the RCS system. The applicant was further requested to explain and justify why the lower frequency and lower temperature differences support the basis for not monitoring Transient 14.

By letter dated March 28, 2014, the applicant responded to RAI 4.3.1-4. The applicant stated that it compared the frequency of chemistry samples and temperature difference between the original sample location and design assumptions with the actual sample location and plant procedures. The applicant stated that the original design transient cycle basis assumed that samples were taken three times a day, over a 40-year plant life, totaling 45,000 cycles. The applicant further stated that, based on actual chemistry procedures as confirmed by operator interviews, RCS samples are taken only once per day during power operations and up to a maximum of once per hour, for a maximum of 3 days, during each heatup and cooldown. The applicant stated that the reactor coolant sampling location was changed in approximately 2002 such that chemistry samples were drawn downstream of the Chemical Volume and Control System letdown heat exchangers. The applicant stated that the maximum number of thermal cycles experienced by the original sample piping from the RCS, based on Byron, Unit 1, which has been in service the longest, is estimated to be approximately 11,000 cycles. The staff noticed that in 2002, Byron, Unit 1, had been in operation for approximately 17 years. The applicant stated that when samples were originally taken from the RCS sampling line piping, the temperature difference in the RCS sample line piping was approximately 480 °F to 580 °F. The applicant stated that the temperature difference when taking samples from the letdown heat exchangers is considerably less at approximately 90 °F to 150 °F.

The staff finds it reasonable that Transient 14 in LRA Tables 4.3.1-2 and 4.3.1-5 does not require monitoring by the Fatigue Monitoring program because there is adequate margin between the actual plant occurrence at 11,000 and the design limit of 45,000 when originally taken from the RCS sample line. Since the current plant procedures, which were applied approximately in 2002, require less frequent sampling at a considerably lower temperature difference, the staff finds it reasonable that an adequate margin will be maintained through the period of extended operation. The staff finds the applicant's response to RAI 4.3.1-4 acceptable. The staff's concern in RAI 4.3.1-4 is resolved.

The staff finds that the applicant has demonstrated that it monitors all transients that cause cyclic strain, which support its fatigue analyses with its enhanced Fatigue Monitoring program, such that corrective actions are taken prior to exceeding design limits, including environmental effects when applicable.

LRA Section 4.3.1 states that, since the transients have been projected to the end of the period of extended operation, this section has been dispositioned in accordance with 10 CFR 54.21(c)(1)(ii). The LRA states the transients are used as inputs in the metal fatigue TLAA evaluations in the remainder of LRA Section 4.3. Because the applicant did not provide any analysis, the staff determined that this section does not include a TLAA in accordance with 10 CFR 54.3(a).

4.3.1.3 UFSAR Supplement

LRA Sections A.4.3.1 and A.3.1.1 provide the UFSAR supplement summarizing the applicant's basis of its fatigue analyses and describing its Fatigue Monitoring program to ensure that the numbers of transients actually experienced remain below the assumed number. The staff reviewed LRA Section A.4.3.1 and A.3.1.1, consistent with the review procedures in SRP-LR 4.3.3.2, which state that the reviewer should confirm that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR 4.3.2.2. Additionally, the staff determined that the applicant provided an adequate summary description for its Fatigue Monitoring program to monitor the number of transients actually experienced, as required by 10 CFR 54.21(d).

4.3.1.4 Conclusion

On the basis of its review, that staff concluded that the applicant provided an adequate description and acceptable basis for monitoring design transients and cycles with its Fatigue Monitoring program. The program ensures that corrective actions are taken prior to exceeding the design limit during the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the monitoring bases of transients and design cycles, as required by 10 CFR 54.21(d).

4.3.2 ASME Code Section III, Class 1 Fatigue Analyses

4.3.2.1 Summary of Technical Information

LRA Section 4.3.2 states that the BBS reactor vessels and RCPB piping, components, and auxiliary lines were designed in accordance with ASME Code Section III, Class 1 requirements. Fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature, pressure, and seismic loading cycles. The LRA states that some ASME Code Section III, Class 2 heat exchangers also have fatigue analyses, which were performed in a manner similar to that used for Class 1 components. The fatigue analyses were required to demonstrate that the CUF will not exceed the design allowable limit of 1.0 when the equipment is exposed to all of the postulated transients. Since the calculation of fatigue usage factors is part of the CLB and is used to support safety determinations and since the number of occurrence of each transient type was based upon 40-year assumptions, these fatigue analyses have been identified as TLAAs requiring evaluation for the period of extended operation. The LRA states that these fatigue analyses are based on the transient cycles listed in design specifications, as shown in LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The applicant stated that, in order to ensure the numbers of transients remain bounding of those used in the fatigue analyses, the Fatigue Monitoring program will be used to monitor transients and ensure corrective action is taken prior to exceeding any design cycle limit.

LRA Section 4.3.2 also states that the design analysis of some BBS ASME Code Section III, Class 1 components also used the fatigue exemption provisions of ASME Code Section III, Subparagraphs NB-3222.4(d) (1) through (6). The applicant further states that some ASME Code Section III, Class 2 and 3 components at BBS were designed to ASME Code Section III, Paragraph NC-3219 requirements and were shown to meet the criteria for a fatigue exemption per ASME Code Section III, Subparagraphs NC-3219.2 and NC-3219.3. Since these fatigue exemptions are based upon the 40-year design transients, they have also been identified as TLAAs that require evaluation for the period of extended operation. The LRA states that, in order to demonstrate acceptability from a fatigue exemption basis for the period of extended operation for Classes 1, 2, and 3 components, the transients considered are based on the transients in LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The applicant stated that the Fatigue Monitoring program will be used to ensure these cycles will not be exceeded during the period of extended operation.

The applicant dispositioned the ASME Code Section III, Class 1 fatigue analyses, the ASME Code Section III, Class 2 heat exchangers fatigue analyses, and the ASME Code Section III, Class 1, Class 2, and Class 3 fatigue exemptions in accordance with 10 CFR 54.21(c)(1)(iii) such that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

4.3.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2 and the TLAAs for the ASME Code Section III, Class 1, Class 2, and Class 3 fatigue analyses to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

The staff reviewed the applicant's TLAAs for the ASME Code Section III, Class 1, Class 2, and Class 3 fatigue analyses, and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

LRA Section 4.3.2 states that the fatigue analyses and fatigue exemptions for BBS ASME Code Section III, Class 1 vessel, piping, and components are based on the transients listed in LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The LRA also states that several ASME Code Section III, Class 2, heat exchangers have fatigue analyses that were evaluated similar to those used for Class 1 components. The LRA further states that the transients assumed to demonstrate acceptable fatigue exemption bases for ASME Code Section III, Class 1, Class 2, and Class 3 components are included in LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The LRA states that the Fatigue Monitoring program is credited to monitor the transient cycles and require corrective action prior to exceeding the design limits.

The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

The staff finds that the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to metal fatigue of the ASME Code Section III, Class 1 vessels, piping, and components, ASME Code Section III Class 2 heat exchangers, and components associated with ASME Code Section III Class 1, Class 2, and Class 3 fatigue exemptions will be adequately managed through the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Fatigue Monitoring program monitors and tracks the transient cycles assumed in the analysis and requires corrective action prior to exceeding the number of transient cycles used in the analysis.

4.3.2.3 UFSAR Supplement

LRA Section A.4.3.2 provides the UFSAR supplement which summarizes the TLAA for ASME Code Section III, Class 1 fatigue analyses, ASME Code Section III, Class 2 heat exchanger fatigue analyses, and ASME Code Section III, Class 1, Class 2, and Class 3 fatigue exemptions. The staff reviewed LRA Section A.4.3.2 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.3.2 meets the acceptance criteria in SRP-LR 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for ASME Code Section III, Class 1 fatigue analyses, ASME Code Section III, Class 2 heat exchanger fatigue analyses, and ASME Code Section III, Class 1, Class 2, and Class 3 fatigue exemptions as required by 10 CFR 54.21(d).

4.3.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue on the intended functions of the ASME Code Section III, Class 1 vessels, piping, and components, ASME Code Section III Class 2 heat exchangers, and components associated with ASME Code Section III Class 1, Class 2, and Class 3 fatigue exemptions will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3 ASME Code Section III, Classes 2 and 3 and ANSI B31.1 Allowable Stress Analyses

4.3.3.1 Summary of Technical Information

LRA Section 4.3.3 describes the applicant’s allowable secondary stress range reduction factor TLAAs for ASME Code Section III, Class 2 and 3, and ANSI B31.1 piping. A stress range reduction factor to the allowable stress range is required if the number of equivalent full temperature cycles exceeds 7,000. The applicant stated that these are considered to be implicit fatigue analyses since they are based upon cycles anticipated for the life of the component, and are therefore, TLAAs requiring evaluation for the period of extended operation.

<u>Piping and Components Designed in Accordance with ASME Section III, Class 2 and 3, and ANSI B31.1 Associated with the RCS and Auxiliary Systems Transients</u>. LRA Section 4.3.3 states that ASME Code Section III, Class 2 and 3 piping at BBS was designed to ASME Code Section III, Paragraph NC-3611, ASME Code Section III, Paragraph ND-3611, and ANSI B31.1 requirements. The applicant stated that the cyclic qualification of the piping is based on the number of equivalent full temperature cycles as listed in LRA Table 4.3.3-1. LRA Tables 4.3.1-3 and 4.3.1-6 list the transients and their 60-year projections for the Class 2, Class 3, and ANSI B31.1 piping considered to experience transients associated with the RCS and Auxiliary Systems. This transient set is a subset of the transients found in LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The applicant further states that, as demonstrated by LRA Tables 4.3.1-3

and 4.3.1-6, the number of projected cycles is less than 7,000, and therefore, the fatigue analyses for these Class 2, Class 3, and ANSI B31.1 piping will remain valid through the period of extended operation. The applicant dispositioned these TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) such that the Fatigue Monitoring program will monitor the transient cycles and severities and require action prior to exceeding design limits that would invalidate these conclusions.

Auxiliary Feedwater, Emergency Diesel Generator, Fire Protection, Heating Water and Heating Steam, and Service Water System ANSI B31.1 Piping and Components. LRA Section 4.3.3 states that, for the remaining systems that are affected by different thermal and pressure cycles, an operational review was performed that concluded that the total number of cycles projected for 60 years are significantly less than 7,000 cycles. This includes the AFW, emergency diesel generator (EDG), fire protection, heating water and heating steam system, and service water systems. The applicant stated that, since the projected number of transient cycles does not exceed the number of equivalent full temperature cycles assumed in the implicit stress analysis, the stress range reduction factors originally selected for the components in all of these systems remain applicable, and therefore the TLAAs remain valid for the period of extended operation. The applicant dispositioned these TLAAs in accordance with 10 CFR 54.21(c)(1)(i) such that the ASME Code Section III, Class 2 and 3, and ANSI B31.1 allowable stress calculations for the AFW, EDG, fire protection, heating water and heating steam, and service water system remain valid for the period of extended operation.

4.3.3.2 Staff Evaluation

Piping and Components Designed in Accordance with ASME Code Section III, Classes 2 and 3, and ANSI B31.1 Associated with the RCS and Auxiliary Systems Transients. The staff reviewed LRA Section 4.3.3 and the TLAA for ASME Code Section III, Class 2 and 3, and ANSI B31.1 piping and components associated with the RCS and Auxiliary Systems for which the allowable range of secondary stresses depends on the number of assumed thermal cycles to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

The staff reviewed the applicant's TLAAs and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.2.3. These procedures state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected piping and components.

The staff reviewed the 60-year projected cycle counts for the plant transients provided in LRA Tables 4.3.1-3 and 4.3.1-6 to ensure that the full thermal range transient cycle limit of 7,000 will not be exceeded. The total number of design basis thermal events expected to occur in a 60-year life is approximately 2,900 each for Byron, Units 1 and 2, and approximately 1,800 each for Braidwood, Units 1 and 2. The staff concluded that there is an adequate margin to account for unanticipated transient occurrences such that the full-range thermal cycle limit of 7,000 will not be exceeded during the period of extended operation.

The LRA states that the Fatigue Monitoring program is credited to monitor the transient cycles and require corrective action prior to exceeding the design limits that would invalidate this analysis. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

The staff finds that the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to metal fatigue on the intended functions of the ASME Code Section III, Class 2 and 3, and ANSI B31.1 piping and components associated with the RCS and Auxiliary Systems will be adequately managed through the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.2.3 because the applicant's Fatigue Monitoring program monitors and tracks the transient cycles assumed in the analysis and requires corrective action prior to exceeding the number of transient cycles used in the analysis.

Auxiliary Feedwater, Emergency Diesel Generator, Fire Protection, Heating Water and Heating Steam, and Service Water System ANSI B31.1 Piping and Components. The staff reviewed LRA Section 4.3.3 and the TLAA for the ANSI B31.1 piping and components associated with the AFW, EDG, fire protection, heating water and heating steam, and service water systems for which the allowable range of secondary stresses depends on the number of assumed thermal cycles to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.2.1. These procedures state that the relevant information in the TLAA, operating plant transient history, design basis, and the CLB are reviewed to confirm that the maximum allowable stress range values for the existing fatigue analysis remain valid for the period of extended operation and that the allowable limit for full thermal range transients will not be exceeded during the period of extended operation.

The LRA states that an operational review was performed that concluded that the total number of cycles projected for 60 years for these systems are significantly less than the full-range thermal cycle limit of 7,000. However, the LRA did not contain enough information regarding the applicable thermal cycles and 60-year projections associated for these systems.

By letter dated February 26, 2014, the staff issued RAI 4.3.3-1 requesting that the applicant provide the transients used in the implicit fatigue for the ANSI B31.1 piping and components associated with the AFW, EDG, fire protection, heating water and heating steam, and service water systems. The applicant was requested to provide the 60-year projected cycle counts and justify that the TLAA remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

By letter dated March 28, 2014, the applicant responded to RAI 4.3.3-1. The applicant stated the transients used in the implicit fatigue analysis of the: (a) AFW system are the number of AFW pump diesel engine starts and stops, (b) EDGs are the number of diesel engine starts and stops, (c) fire protection system are the number of fire pump diesel engine starts and stops, and (d) Byron service water system are the number of essential service water makeup pump diesel engine starts and stops. The applicant stated that a diesel engine startup, run, and shutdown is counted as one temperature transient for these systems. The applicant further stated that each diesel engine is started and shutdown once a month for surveillance to satisfy the TSs. The applicant projected approximately 720 thermal cycles for surveillance testing over a 60-year life. The applicant also stated that it projected an additional 720 thermal cycles to account for when a diesel engine is called upon to run and perform its intended function, run for additional surveillance testing requirements, run during spurious starts, or run as a result of maintenance activities. The applicant stated that the total 60-year projected cycle count for these DGs is approximately 1,440 cycles.

The applicant also stated that transients used in the implicit fatigue analysis for the Heating Water and Heating Steam System are the number of auxiliary steam system startups and shutdowns. The applicant stated that the auxiliary steam system, which is common to both units, is used as a backup when the extraction steam supply from both units is simultaneously lost (i.e., dual unit outage). The applicant stated that the 60-year thermal cycle count is projected to be no more than the maximum projected occurrences of plant cooldowns and heatups, reactor trips, and surveillances for a single auxiliary steam boiler. The applicant clarified that Byron Unit 1 is used because it has the greatest number of projected occurrences, which the staff noticed as conservative. The applicant stated that the Byron Unit 1 projects, for a 60-year period, 180 auxiliary steam boiler surveillances, 117 cycles of reactor cooldowns and heatups, and 71 cycles of reactor trips. The applicant stated that this results in a 60-year projection of 368 cycles.

The staff finds the applicant's response to RAI 4.3.3-1 acceptable because the applicant provided the associated transients and its 60-year projections assumed in the implicit analyses and provided adequate demonstration that the cumulative 60-year projected cycles for transients defined as full thermal range transients will remain less than the 7000 cycle allowable and that the analyses remain valid for the period of extend operation. The staff's concern in RAI 4.3.3-1 is resolved.

Based on its review, the staff finds it reasonable that the full-range thermal cycle limit of 7,000 – used in the applicant design basis fatigue evaluations associated with the ANSI B31.1 and ASME Code Section III, Class 2 and 3, piping and components – will not be exceeded and includes margin to account for unanticipated transient occurrences during the period of extended operation.

The staff finds that the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAAs for the ANSI B31.1 piping and components associated with the AFW, EDG, fire protection, heating water and heating steam, and service water systems for which the allowable range of secondary stresses depends on the number of assumed thermal cycles remain valid for the period of extended operation. Additionally, the applicant's analysis meets the acceptance criteria in SRP-LR 4.3.2.1.2.1 because the applicant demonstrated, for those piping and components subject to thermal fatigue described above, the cycle limit for full thermal range transients established in the design analyses will not be exceeded, and therefore the analysis will remain valid for the period of extended operation.

4.3.3.3 UFSAR Supplement

LRA Section A.4.3.3 provides the UFSAR supplement summarizing the TLAA for ANSI B31.1 or ASME Code Section III, Class 2 and 3, piping and components. The staff reviewed LRA Section A.4.3.3 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAAs.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for ANSI B31.1 or ASME Code Section III, Class 2 and 3, piping and components, as required by 10 CFR 54.21(d).

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the ASME Code Section III, Class 2 and 3, and ANSI B31.1 piping and components associated with the RCS and Auxiliary Systems will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAA for ANSI B31.1 piping and components associated with the AFW, EDG, fire protection, heating water and heating steam, and service water systems remains valid for the period of extended operation. The staff further concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluations, as required by 10 CFR 54.21(d).

4.3.4 Class 1 Component Fatigue Analyses Supporting GSI-190 Closure

4.3.4.1 Summary of Technical Information

LRA Section 4.3.4 describes the applicant's evaluation of the effects of the reactor coolant environment on component fatigue life for the period of extended operation. The applicant assessed the environmental effects on fatigue at the six sample locations identified by NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," for newer vintage Westinghouse plants.

The applicant stated that it performed a systematic review of all Safety Class 1 RCPB components in major equipment and piping systems with a fatigue analysis that are susceptible to EAF to ensure that the limiting plant-specific EAF locations have been identified. The LRA states that the methodology in NUREG/CR-5704 (for austenitic stainless steel (SS) components), NUREG/CR-6583 (for carbon/LAS components), and NUREG/CR-6909 (for nickel alloy components) were used to determine applicable values of environmental fatigue life correction factor (F_{en}) for each material type. These values of F_{en} were then used to evaluate CUFs that include environmental effects (CUF_{en}).

The LRA states that the screening process for identifying the limiting locations for EAF divided the Safety Class 1 components into applicable transient sections. The applicant stated that the maximum/bounding F_{en} factors were applied to each of the components in the transient sections based on the material. The applicant then screened out all components with the resulting CUF_{en} of less than 1.0. The applicant used a stress basis comparison to identify the leading locations in each transient section. The applicant ranked the stress analysis methodology applied to each of the component CUFs based the level of technical rigor. The applicant also compared the remaining components of different transient sections that reside in the same piping system or equipment using the CUF_{en} and stress analysis method comparison to remove any additional components from consideration. The resulting leading locations supplemented the locations identified in NUREG/CR-6260.

LRA Table 4.3.4-1 provides the summary of the CUF_{en} values of the NUREG/CR-6260 locations for BBS. LRA Tables 4.3.4-2 and 4.3.4-3 provide the plant-specific EAF screening leading location results. LRA Section 4.3.4 states that the results of the evaluation of other locations from LRA Tables 4.3.4-2 and 4.3.4-3 determined to be potentially limiting will be incorporated into the Fatigue Monitoring program prior to the period of extended operation.

The applicant dispositioned the evaluations associated with EAF of the NUREG/CR-6260 locations for a newer vintage Westinghouse plant in accordance with 10 CFR 54.21(c)(1)(iii), such that the effects of EAF on the intended functions will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

4.3.4.2 Staff Evaluation

The staff found that the applicant addressed the effects of the reactor coolant environment on component fatigue life consistent with the guidance in the SRP-LR and the staff's recommendations for resolving Generic Safety Issue No. 190 (GSI-190), dated December 26, 1999. The staff also identified that, consistent with Commission Order No. CLI-10-17, dated July 8, 2010 (ADAMS Accession No. ML101890775), the evaluations associated with the effects of the reactor coolant environment on component fatigue life are not TLAAs in accordance with the definition in 10 CFR 54.3(a), because these evaluations are not in the applicant's CLB. Nevertheless, the applicant has credited its Fatigue Monitoring program to manage the effects of reactor coolant environment on component fatigue life. Therefore, the staff reviewed LRA Section 4.3.4 and the evaluations for EAF to confirm, 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 reviewed the applicant's EAF evaluations, as presented in the LRA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.3.3.1.3, which state that the reviewer should confirm that the applicant has addressed the effects of the reactor coolant environment on component fatigue life as AMPs are formulated in support of license renewal.

In its review of LRA Section 4.3.4, the staff noticed that this sample of critical components with high-fatigue usage locations should include the locations identified in NUREG/CR-6260, as a minimum, as well as additional locations based on plant-specific considerations. LRA Section 4.3.4 states that 60-year fatigue calculations were performed for these component locations. The LRA states that the methodology in NUREG/CR-5704 (for austenitic SS components), NUREG/CR-6583 (for carbon/LAS components), and NUREG/CR-6909 (for nickel alloy components) were used to determine applicable F_{en} factors and obtain an environmentally adjusted cumulative fatigue usage (CUF_{en}) which included the effects of the reactor water environment. The LRA further states that applicable 60-year projected numbers of transients, which are included in the tables in LRA Section 4.3.1, were used in the EAF evaluations when necessary.

The LRA states that the applicable transient sets to be analyzed for the EAF evaluations for each component were determined by reviewing the transient definitions in the design specifications and the corresponding fatigue analyses. The applicant stated that plant-specific data, when available, were incorporated into the EAF analysis to reduce conservatism on an as-needed basis for qualification. The staff noticed that the applicant did not identify what plant-specific data were used and which evaluations used the plant-specific data to reduce conservatism. The staff noticed that the applicant also did not identify which analyses used 60-year projected cycles.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-1, requesting the applicant to: (a) identify the EAF evaluations in which plant-specific data were issued, (b) describe the plant-specific data used to reduce conservatism, and (c) justify the use of the plant-specific data in the EAF evaluations. The staff also requested that the applicant identify the EAF evaluations, including specific transients and cycles for each location, in which 60-year projected cycles and/or reduced number of cycles were used.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-1. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that plant-specific data were used to reduce conservatism for the EAF evaluations of the charging nozzles and the pressurizer spray nozzle. The applicant stated that the CLB transients and cycle counts were used for all other EAF evaluations.

The applicant provided the following information in its RAI 4.3.4-1 response. For the charging nozzle EAF evaluation, the applicant stated that conservatism was reduced for the original Transient 6, “Letdown Flow Shutoff Prompt Return to Service” design transient, which is included in LRA Tables 4.3.1-2 and 4.3.1-5. The applicant stated that the parameters reviewed for this transient include regenerative and letdown heat exchanger outlet temperatures, charging and letdown flows, and reactor coolant loop (RCL) temperatures. The applicant also stated that actual operating transients were less severe than the design transients based on comparison of these actual plant-specific transient data against the original design transients. The applicant stated that its review of the plant data showed that (1) a large number of transient cycles associated with flow isolation design transients were below the temperature changes associated with the design transient, but (2) the total number of transient cycles exceeded the number of cycles assumed in the original design analysis. The applicant stated that the cycles were counted within various bounding maximum temperature difference ranges for each unit. The applicant stated that these four bounding redefined transients were inputs to the EAF evaluation for the charging nozzle. The staff determined that the applicant provided additional information for these transients in its response to RAI 4.3.1-1, which was found acceptable as described in SER Section 4.3.1.2.

The applicant also provided the following information in its RAI 4.3.4-1 response. For the pressurizer spray nozzle EAF evaluation, the applicant stated that the plant-specific data were used to reduce conservatism for the “Plant Heatup” and “Plant Cooldown” design spray transients. The applicant stated that the parameters reviewed for these transients include pressurizer spray line temperature, pressurizer spray line flow demand, pressurizer steam and water temperatures, and RCL temperatures. The applicant stated that the design heatup and cooldown transients were defined with a conservative number of spray events and spray nozzle change in temperature values. The applicant stated that it reviewed plant-specific data for the period of 1999 to 2012 and determined the cycle counts from the reduced data set and prorated counts over past operation and future operation. The applicant stated that the extrapolation was justified based on operator interviews and reviews of plant operating procedures that affect pressurizer spray operation, which did not change significantly from initial startup through 1999. The applicant stated that the bounding redefined “Plant Heatup” and “Plant Cooldown” transients were inputs to the pressurizer spray EAF evaluations. The staff finds this evaluation acceptable because the applicant reviewed actual plant-specific data on spray event occurrences and spray flow demands to determine the bounding redefined cycle counts that were used as inputs to the EAF evaluations.

In its response to RAI 4.3.4-1, the applicant also provided transients and EAF evaluation cycles which were the 60-year projected cycles and/or reduced number of cycles used in the EAF evaluations. The applicant identified four locations for these EAF evaluations: charging nozzles, accumulator nozzles, safety injection nozzles, and the pressurizer spray nozzle. The applicant stated that the limiting number of cycles was used in the EAF evaluations and the reduced cycles used for the EAF evaluations will become the CLB cycle limits for the period of extended operation. The applicant stated that these transients will be monitored and tracked by the Fatigue Monitoring program and will require corrective action prior to exceeding the cycle limits.

The staff finds the applicant's response acceptable because the applicant identified the EAF locations which used plant-specific data to reduce conservatism. The staff confirmed that the applicant provided an adequate justification for the use of the plant-specific data to provide more-accurate CUF_{en} values for the locations evaluated. The staff also finds the response acceptable because the applicant provided the list of transients and locations where 60-year projected cycles or reduced number of cycles were used in the EAF evaluations. The staff finds acceptable that the most limiting number of cycles will be monitored and tracked by the Fatigue Monitoring program at each BBS unit, since this ensures corrective actions can be taken before exceeding a transient count limit. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24. The staff's concerns in RAI 4.3.4-1 are resolved.

In LRA Section 4.3.4 the applicant stated that the objective of the EAF evaluation methodology was to reduce conservatism in the stress analyses as needed to accommodate the additional F_{en} on the CUF values. The applicant stated that WESTEMS™ (trademarked software technology developed by the Westinghouse Electric Company) was used to determine detailed stress histories for each applicable transient, which considered all applicable mechanical and thermal transient loads during each transient, and to calculate fatigue usage. The applicant stated that the stress histories were used to determine the stress peaks and valleys for the fatigue evaluations. The LRA states that the WESTEMS™ fatigue calculation methodology uses a conservative algorithm for the selection of the stress peaks and valleys for use in the ASME fatigue evaluations. The applicant stated that the analysis can use the optional program tools to remove conservatism to produce a more accurate final result. The applicant stated that when an analyst utilizes these program tools to remove conservatism, the justification of peak removal is fully documented and included in the supporting calculations. The applicant stated that, otherwise, the ASME fatigue evaluations retained the inherent conservatism in the WESTEMS™ software. The staff noticed that the applicant did not clarify whether these optional program tools were used to remove conservatism for fatigue evaluations.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-2, requesting that the applicant identify all of the fatigue evaluations in which the optional program tools in the WESTEMS™ software was used to remove conservatism. The staff also requested that the applicant provide examples of the program tool use, provide the basis for removing conservatism, and justify that a more accurate final result was produced.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-2. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that the optional program tools in the WESTEMS™ software were used for the fatigue evaluations of the

RCL safety injection nozzles, RCL accumulator nozzles, and the pressurizer spray nozzle. The applicant stated that the optional program tool in the software was the use of peak editing tools and that the peaks removed in these evaluations were determined to be non-controlling, redundant, and resulted in unnecessary conservatism. The applicant also provided an example where the peak editing tools were applied for each of the three components. For each of the three examples, the applicant provided a figure to show a plot in the WESTEMS™ software of two stress intensities for the transient. The applicant stated the resulting analysis removes unnecessary conservatism and results in more accurate usage factors.

The staff finds the applicant response acceptable because the applicant identified the components in which the WESTEMS™ software operational program tools were used in the fatigue evaluations and provided examples of how the program tools were used. The staff further finds the response acceptable because the applicant's use of the peak removal tools in the WESTEMS™ software is documented and removes redundant stress peaks to provide a more accurate CUF_{en}, consistent with the discussion in RIS 2011-14, "Metal Fatigue Analysis Performed By Computer Software," December 29, 2011. The staff's concerns in RAI 4.3.4-2 are resolved.

To ensure that the limiting plant-specific EAF locations have been identified, in LRA Section 4.3.4, the applicant stated that a systematic step-wise review was performed for all Safety Class 1 RCPB components in major equipment and piping systems with a fatigue analysis and susceptible to EAF. The applicant stated that these components were reviewed and categorized into common groups as part of the EAF screening process. The four steps, which are evaluated sequentially below, are:

(1) grouping into transient sections
(2) use of screening F_{en} values to eliminate locations with CUF_{en} values less than 1.0
(3) stress basis comparison to identify leading locations
(4) comparison of locations from different transient sections

The first step in this screening methodology groups the Class 1 components into transient sections, which are defined as groups of subcomponents/locations that experience the same transients. The applicant further stated that the components residing in the same transient section can easily be compared with each other to determine the most limiting component (or leading location), which is the location with the highest CUF value. The applicant stated that the differences in stresses experienced by each component in a transient section are generally the result of the material and geometry differences. The staff finds this first step in the screening methodology appropriate because the applicant included all Safety Class 1 RCPB components susceptible to the reactor coolant water environment in the scope of its EAF evaluation to identify any plant-specific components.

The second step of the screening methodology is to develop environmental correction factors (F_{en}) for each component so that CUF values including environmental fatigue (CUF_{en}) can be calculated. The applicant stated that those components with a screening CUF_{en} of less than 1.0 were removed from the list because they have been calculated using the design-basis fatigue usage factors with a maximum F_{en} based on material. The staff noticed that the applicant did not clarify whether the "maximum F_{en}" is the maximum calculated from the NUREG reports or whether it is the maximum calculated for a particular transient section. The staff noticed that, if it is the latter, it is important to understand the applicant's assumptions in calculating the maximum F_{en} based on material for a particular transient section.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-7, requesting that the applicant clarify whether the maximum F_{en} based on the material is the calculated maximum F_{en} from the applicable NUREG reports or the calculated maximum from a particular transient section. If the maximum F_{en} was based on the transient section, the staff requested that the applicant identify any assumptions (e.g., temperature, sulfur, dissolved oxygen (DO), strain rate) used in calculating the F_{en} and the basis for these assumptions.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-7. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that bounding temperature, sulfur, DO, and strain rate parameters were assumed such that use of the parameters would result in the maximum material F_{en} values from the applicable NUREG report that was applied to the component's material. The applicant stated that the only exception was that a value of 0.005 ppm was used for the DO content and that it reviewed its plant chemistry data to confirm that DO content is 0.005 ppm during normal operation and 0.05 ppm during heatup and cooldown operations. The applicant stated that the elevated DO content usually only occurs when reactor coolant temperature is low and in the fluid temperature range where the transformed metal temperature parameter is zero. The applicant stated that it used these maximum material F_{en} values to screen components within the transient sections with CUF_{en} values below 1.0. The applicant also stated that it further refined the F_{en} values based on the maximum temperature and applied them to the remaining components. The applicant stated that it again removed components with CUF_{en} values below 1.0 from consideration. The staff finds the applicant's response acceptable because the applicant provided adequate justification for its assumptions made in determining F_{en} factors, which the staff concluded were bounding. The staff finds the applicant's use of the lower DO content acceptable because the applicant used plant-specific operating data to determine the value during normal operation and during heatup and cooldown. The staff's concerns in RAI 4.3.4-7 are resolved.

The staff recognized that, in order to determine the most limiting component (or leading location) with the highest CUF value, it is important that the CUFs are assessed using the same fatigue curves in ASME Code Section III, Appendix I. The staff further noticed that the LRA did not clarify whether the applicant had considered any differences in component materials when performing its review to compare component CUF values, since material properties may impact the specific CUF value for a given component. The staff reasoned that, through the course of plant operation, it is possible that CUF values for specific components were re-evaluated as part of power uprates, responses to GLs or bulletins, etc., to different editions of ASME Code Section III and with varying levels of rigor when compared to the fatigue evaluations performed for the plant's original design.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-3, requesting that the applicant confirm that the CUF values that were compared with each other in a transient section to identify the location with the highest CUF value were assessed similarly (e.g., amount of rigor in calculating CUF) and used the same fatigue curves in ASME Code Section III, Appendix I to provide a meaningful comparison. If not, the staff requested that the applicant provide the basis for ranking or comparing the CUF values to one another to provide an appropriate method for screening and determining a leading/limiting location. The staff further requested that the applicant clarify whether CUF values of different material types were compared to one another when determining the leading location(s) within a transient section. If so, the applicant was requested to identify the transient section, locations and materials that have been compared and eliminated for consideration of EAF; otherwise the applicant was requested to justify that the comparison of CUF values between different materials within a transient section for the consideration of EAF is appropriate or valid.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-3. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that locations within a transient section were compared similarly in regards to the amount of rigor used in calculating the CUF. The applicant stated that, within a transient section, all locations with materials other than nickel alloy used the same fatigue curves from the ASME Code Section III, Appendix I. The applicant stated that the NUREG/CR-6909 fatigue curves were used to compare nickel alloy component locations with the component locations made from different materials. The applicant stated that the EAF screening evaluation for transient sections associated with equipment locations considered different materials. In its response to RAI 4.3.4-3, the applicant described its EAF screening evaluation of the reactor vessel outlet nozzle region to provide an example of the applicant's review of Class 1 components with different material types. The applicant stated that the reactor vessel outlet nozzle region consists of SS (safe end), LAS (nozzle), and nickel alloy (safe end to nozzle weld). The applicant stated that the F_{en} factors applied to the respective CUFs were calculated using NUREG/CR-5704 for the safe end, NUREG/CR-6583 for the nozzle, and NUREG/CR-6909 for the safe end to nozzle weld. The applicant stated that the leading location for this transient section was the safe end location because it produced the highest screening CUF_{en} greater than 1.0. The staff identified that, within a transient section that contains components of various materials (e.g., LAS, nickel alloy, SS), the applicant did not provide a basis for selecting a leading location based on the highest CUF_{en} value. The staff determined that the CUF_{en} value of different materials may respond differently when the EAF is being refined in the future. In the example of the reactor vessel outlet nozzle region, the applicant did not provide sufficient justification that the SS component would bound the components made from other materials after the EAF has been refined to reduce the CUF_{en} of the SS component. More generally, the applicant did not justify that the refinement of the higher CUF_{en} of one material would ensure the reduction of CUF_{en} values for another material within the same transient section.

By letter dated June 30, 2014, the staff issued followup RAI 4.3.4-3a, requesting the applicant to provide additional information and justification that one material can serve as the leading location for other material locations with CUF_{en} values greater than 1.0 within a transient section. The applicant had initially responded to RAI 4.3.4-3 in a letter dated March 28, 2014, which was withdrawn and resubmitted by letter dated September 11, 2014. The staff reviewed both versions and confirmed that the information provided remained the same; therefore, the context of RAI 4.3.4-3a was not affected.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-3a. The applicant provided its principles and bases for choosing a location made from one material to serve as the leading location for components within the same transient section that are made from different materials. The applicant stated that there are four transient sections at BBS that included components of different materials. For each of these transient sections, the applicant first evaluated components of similar materials separately to determine if any components can be screened out. The applicant applied the screening CUF_{en} evaluation, which is described in the second step of the methodology, and the stress basis analysis, which is described in the third step of the methodology. The staff's evaluation of this third step of the methodology, the stress basis analysis, is documented later in SER Section 4.3.4.2. The applicant then compared the remaining components within the transient section. To justify selecting the leading location(s) to bound the other components of differing materials, the applicant stated that it applied bases dependent on the screening CUF_{en} values, the conservatism of the analysis method, and the range of the potential reduction F_{en} of each component and material.

In its evaluation of the reactor vessel transient section, the applicant provided its justification to select the outlet nozzle safe ends as the leading location. The applicant stated that the outlet nozzle safe end weld and nozzle body locations were removed from consideration because refined evaluations using the maximum screening F_{en} values resulted in screening CUF_{en} values below 1.0. The staff finds this evaluation and leading location selection for the reactor vessel transient section acceptable because the applicant applied the maximum screening values to the components and will monitor, per Commitment No. 43, the component with resulting CUF_{en} values above 1.0.

In its evaluation of the Unit 2 original steam generator (OSG) transient section, the applicant first compared components for each material separately to screen out components from consideration. The applicant stated that the remaining components were the primary manway (pad/shell) – drain hole in channel head, which is carbon steel; the primary chamber drain, which is nickel alloy; and the tubesheet and shell junction, which is low-alloy steel. The applicant also stated that the tubesheet and shell junction can be removed because the fatigue curves from NUREG/CR-6583 were used for both this component and the carbon steel primary manway (pad/shell) – drain hole in channel head. Because the tubesheet and shell junction had a lower screening CUF_{en} and was evaluated with a more conservative EAF methodology, the primary manway (pad/shell) – drain hole in channel head can bound this component. The staff finds the removal of the tubesheet and shell junction from consideration acceptable because: (a) the two materials could be compared on the same basis because the same fatigue curves were used, and (b) the applicant retained the component with the higher screening CUF_{en} value and more rigorous EAF evaluation method. The applicant stated that it also will retain the nickel alloy primary chamber drain for this transient section. The staff finds the applicant's selection of leading locations for the Unit 2 OSG transient section acceptable because the applicant justified the bounding locations for each material within the transient section and will monitor, per Commitment No. 43, both resulting components.

In its evaluation of the pressurizer transient section, the applicant provided its justification to: (a) select the surge nozzle structural weld overlay (SWOL) as the leading location and (b) remove the lower head at heater penetration and upper shell locations from consideration. The applicant stated that these eliminated components were analyzed using a more conservative methodology; therefore, more reduction in the CUF_{en} values is expected than for the surge nozzle SWOL. In its evaluation for the Unit 1 RSG transient section, the applicant also applied this same justification to eliminate the inlet & outlet nozzle, weld location. It is unclear to the staff how this justification would ensure that refinement of the CUF_{en} value of one material could bound the locations of different materials. The applicant did not provide sufficient justification that removing conservatism for one material would result in a proportional refinement for another material. The applicant did not demonstrate that these components would not need to be monitored by the Fatigue Monitoring program for EAF.

Also in its evaluation of the Unit 1 RSG transient section, the applicant removed the primary head drain hole from consideration. The leading location for this transient section, the primary head/tubesheet juncture, has a screening CUF_{en} value of 2.16. The screening CUF_{en} value for the primary head drain hole has a higher screening CUF_{en} value of 2.234 but was analyzed with a more conservative methodology. As part of its stress analysis ranking methodology, the applicant stated that it would only eliminate components from consideration if: (a) its screening CUF_{en} value is lower or the same, and (b) its analysis method is more conservative. However, the applicant justified removing the primary head drain hole by stating that the screening CUF_{en} value for the leading location was only slightly less than the eliminated location. The applicant stated that this is not a concern because the primary head drain hole has a different analysis rank; therefore, the potential reduction in the CUF_{en} value is greater. It is unclear to the staff why the analysis rank difference alone justifies removing this component from consideration. It is also unclear to the staff if there are other instances where the applicant removed components from consideration that had a higher screening CUF_{en} than the selected leading location.

By letter dated October 28, 2014, the staff issued followup RAI 4.3.4-3b, requesting that the applicant provide justification that the refinement of the leading component material analysis would result in the leading component location bounding these component materials within the pressurizer transient section and the Unit 1 RSG transient section. The applicant was also requested to provide justification why the primary head drain hole was removed from consideration when the screening CUF_{en} value was higher than the screening CUF_{en} for the retained leading location and to identify and provide the basis for any other instance where the screening CUF_{en} value for a component removed from consideration was higher than the screening CUF_{en} value for the retained leading location. This issue was identified as Open Item (OI) 4.3-1.

By letter dated November 25, 2014, the applicant responded to RAI 4.3.4-3b. The applicant provided its justification for removing the lower head at heater penetration (pressurizer transient section), the upper shell (pressurizer transient section), and the inlet & outlet nozzle, weld (Unit 1 RSG transient section) locations from consideration for EAF. The applicant's response expanded its response to RAI 4.3.4-3a and further explained how each component met the criteria to allow the component to be removed from consideration from EAF. The criteria applied bases dependent on the screening CUF_{en} values, the conservatism of the analysis method, and the range of the potential reduction F_{en} of each component and material.

For these three components, the applicant stated that an equivalent refinement of the stress analysis basis between the removed component and leading component can be achieved. The applicant stated that the equivalent refinement would be achieved for: (a) the lower head at heater penetration with the use of explicit finite element modeling of component discontinuities, (b) the upper shell with the use of explicit finite element modeling of component discontinuities, reduction of conservative transient adjustments, and reduction of transient grouping, and (c) the inlet & outlet nozzle, weld with the reduction of transient grouping. The applicant stated that these methodologies would continue to result in the screening CUF_{en} values for these components to be lower than the retained leading location.

However, the applicant did not provide sufficient justification or information in its response to ensure that the methodologies used will ensure that the refinement of the fatigue analyses for different materials is equivalent for the specific components. Without quantitative results of analyses, evaluations, or methodologies, the applicant does not have sufficient justification that the refinements of the fatigue analyses for the specific component locations are equivalent. The staff does not have reasonable assurance that the specified components will not need to be monitored for the effects of EAF throughout the period of extended operation.

On January 27, 2015, the staff held a teleconference call with the applicant to discuss a draft followup RAI. During this teleconference, the applicant proposed to monitor these three locations using the Fatigue Monitoring program in the period of extended operation. By letter dated February 6, 2015, the applicant submitted an LRA Amendment. In this amendment, the applicant amended LRA Table 4.3.4-2, which contains the locations at Byron and

Braidwood, Units 1 and 2, that will be monitored for EAF in the period of extended operation. The applicant updated the table to include the lower head at heater penetration (pressurizer transient section), the upper shell (pressurizer transient section), and the inlet & outlet nozzle, weld (Unit 1 RSG transient section) locations. The staff finds this acceptable because: (1) the applicant will monitor these locations with the Fatigue Monitoring program, and (2) with the inclusion of these three locations, the staff has reasonable assurance that the applicant will monitor the bounding locations at Byron and Braidwood, Units 1 and 2, that are susceptible to EAF.

Also in its response to RAI 4.3.4-3b, the applicant provided its justification to remove the primary head drain hole from consideration for EAF. In its justification, the applicant stated that it performed additional stress basis comparisons because this location had a higher screening CUF_{en} value than the retained leading location within the transient section. The applicant stated that the screening CUF_{en} value for the primary head drain hole was less than 4 percent greater than the screening CUF_{en} value of the retained location. The applicant stated that its stress basis comparison evaluation determined that enough refinement of the primary head drain hole analysis can be obtained to justify its removal from consideration. The primary head drain hole was evaluated with a more conservative analysis and has conservatisms that are not applicable to the leading location. One noted conservatism that the applicant provided was that the primary head drain hole fatigue analysis used a conservative inlet/outlet temperature difference in the stress calculation for controlling transients. The applicant stated that it investigated this conservatism impact and determined that it could refine the screening CUF_{en} value by greater than 17 percent.

The staff finds the applicant's basis to remove the primary head drain hole from consideration of EAF acceptable. The applicant provided examples of specific conservatism that impact only the primary head drain hole that could refine the fatigue analysis and CUF_{en} value below that of the retained location. The applicant provided adequate justification in its stress basis comparison that the leading location within the transient section would bound the primary head drain hole for consideration of EAF.

Also in its response, the applicant provided the additional locations that were removed from consideration of EAF but had a higher screening CUF_{en} value than the retained location within its transient section. For these two locations, the hot leg piping location in the reactor coolant pump (RCP) piping transient section and the 3-in. valve butt weld in the pressurizer safety and relief valve (PSARV) piping transient section, additional stress basis comparison evaluations were performed to justify removal from consideration of EAF. The applicant stated that both of these locations were evaluated with a more conservative analysis than the retained leading location in the respective transient section. The applicant identified conservatisms that were unique to the removed locations and not applicable to the retained locations. For the RCP piping transient section, the hot leg piping location analysis was assigned the most conservative and least rigorous ranking. The applicant stated that the conservatisms that were considered for the hot leg piping location and not the retained location included one-dimensional heat transfer analyses, simplified stress intensity range formulas that produced conservative stresses, and absolute combination of stress intensity ranges due to each loading range in NB-3600 equations. The applicant stated these conservatisms would refine the fatigue analyses and the screening CUF_{en} value below that of the retained location. For the PSARV piping transient section, the applicant stated that the finite element analysis used to reduce the stress intensity range terms was done for thermal stress only. The applicant stated that it evaluated the finite element analysis to reduce the stress intensity range term for pressure and determine that the screening CUF_{en} value for the 3-in. valve butt weld could be refined by 50 percent, which would be below the screening CUF_{en} value of the retained location.

The staff finds the applicant's basis to remove the hot leg piping location and the 3-in. valve butt weld acceptable. For both the RCP piping and PSARV piping transient sections, the applicant provided examples of specific conservatism that impact only the removed component that could refine the fatigue analysis and CUF_{en} value below that of the retained location. The applicant provided adequate justification in its stress basis comparison that the leading locations within the transient sections would bound the hot leg piping location and 3-in. valve butt weld for consideration of EAF. The staff's concerns in RAI 4.3.4-3b are resolved. Open Item 4.3-1 is closed.

LRA Section 4.3.4 states that when performing an EAF evaluation, an applicant can either use guidance from NUREG/CR-5704 for austenitic SSs, NUREG/CR-6583 for carbon and low-alloy steels, and NUREG/CR-6909 for nickel alloy, or it can use guidance from NUREG/CR-6909 for all materials. The staff noticed that if NUREG/CR-6909 is used, the corresponding fatigue curves therein should be considered in calculating the CUF values and that this difference must be addressed as part of the EAF screening process. The applicant also indicated that NUREG/CR-6909 was used for nickel alloy locations only. The staff noticed that the applicant did not clarify how many, or if any, nickel alloy components were eliminated based on the CUF_{en} screening process described in the LRA or how the applicant accounted for the difference in fatigue curves used in the fatigue analyses and NUREG/CR-6909 as part of the EAF screening process.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-6, requesting that the applicant identify the nickel alloy locations, or a representative sample set of locations, that were eliminated by the CUF_{en} screening process, including the CUF and F_{en} values for these components. The staff further requested that the applicant discuss and justify how the difference in fatigue curves used in the fatigue analyses of these components and NUREG/CR-6909 was addressed as part of the EAF screening process.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-6. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant provided the component locations that were eliminated by the CUF_{en} screening process and included the values of the associated design-basis CUF, revised NUREG/CR-6909 CUF, F_{en}, and CUF_{en} for the components. The applicant also provided its basis for eliminating each of the locations identified. The applicant stated that the contribution from the NUREG/CR-6909 fatigue curve differences would be negligible in design fatigue evaluations representing low cycle regimes because both methodologies would result in the maximum F_{en} penalty factor. The applicant stated that it performed additional evaluations for design fatigue evaluations representing high cycle regimes to determine the impact of the NUREG/CR-6909 fatigue curves on the ASME Code SS curve used in the CLB analysis. The staff finds the applicant's response acceptable because the applicant confirmed that it performed evaluations to determine the impact of NUREG/CR-6909 fatigue curves on the design-basis CUF values, and provided the resulting CUF_{en} values for the nickel alloy locations that were eliminated. The staff's concerns in RAI 4.3.4-6 are resolved.

The staff finds the applicant's second step in the screening methodology, which developed screening F_{en} factors to calculate CUF and CUF_{en} values, acceptable because the applicant used an appropriate and bounding methodology to determine CUF_{en} values and apply an initial screening criteria to retain components with a CUF_{en} value higher than 1.0 for consideration for EAF. This assured that the piping and components remaining after the initial screening criteria can be compared on an equivalent and conservative level.

The third step in the screening methodology was to perform a stress basis comparison on the remaining components within each transient section to identify the leading locations within the transient sections. The LRA states that Westinghouse has developed an approach that was applied to BBS for performing a stress basis comparison for the components included in the screening process.

The applicant stated that the following stress analysis characteristics were considered in determining the limiting locations within a given transient section:

(1) Qualification Criteria (ASME Code Section III, NB-3200, NB-3600, etc.)
(2) Stress Analysis Technique

Furthermore, the applicant stated that in order to perform these stress basis comparisons, a hierarchy of stress analysis techniques was developed based on fatigue analysis experience, to define the relative complexity of the various techniques.

(1) standard NB-3600 analysis
(2) NB-3600 with nonstandard mechanical stress indices or stress quantities used in stress formulas
(3) NB-3600 with nonstandard thermal stress indices or stress quantities used in stress formulas
(4) combination of (2) and (3)
(5) NB-3200 Fatigue Analysis

The staff concluded that the stress basis comparison described in LRA Section 4.3.4 consists of two aspects: (1) consideration of stress analysis characteristics and (2) a hierarchy of stress analysis techniques. The staff noticed that the LRA indicates that the applicant eliminated certain Safety Class 1 reactor pressure boundary locations susceptible to EAF by performing a "stress basis comparison." The staff also noticed that the LRA did not clarify which locations were eliminated or what the technical basis was for removing these locations from consideration of EAF as a leading location using the stress basis comparison.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-5 requesting the applicant to confirm whether the use of a stress basis comparison and screening CUF_{en} of less than 1.0 were the only methods for eliminating locations for consideration of EAF, or describe and justify any other methods that were used. The applicant was further requested to describe and justify the circumstances and situation when locations were eliminated using a stress basis comparison. The staff also requested that the applicant identify the component locations, or a representative sample set of component locations, that were eliminated as a result of performing this stress basis comparison and to provide its basis for eliminating these locations/components, including any assumptions, factors, or criteria that were used to eliminate these locations for consideration in the EAF calculations.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-5. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that the only methods used for eliminating locations for consideration of EAF were the use of a stress basis comparison and screening CUF_{en} of less than 1.0. The applicant stated that the stress basis comparison is for locations with a CUF_{en} greater than 1.0 in a transient section. The applicant stated that it uses the hierarchy of stress analysis techniques provided in the LRA and ranks them, with (1) Standard ASME NB-3600 analysis as least rigorous to (5) ASME NB-3200 Fatigue analysis as most rigorous. Therefore, a lower stress analysis ranking equates to a less rigorous evaluation technique. The staff finds this ranking of stress analysis techniques based on technical rigor reasonable. The applicant stated that it eliminates locations with lower screening CUF_{en} values and lower stress analysis ranking (hence less rigor). The applicant stated that this approach is justified because if locations with lower stress analysis rankings were refined using a more rigorous stress analysis technique, the resulting CUF_{en} values for the components would be lower. The applicant stated that, when the most limiting component was difficult to determine based on the stress analysis ranking, multiple locations were retained as leading locations. The applicant stated that a component within a transient section could be eliminated only if its screening CUF_{en} value and stress analysis method ranking were lower than another component being retained, which the staff finds appropriate. The applicant also provided its evaluation of the charging lines to provide additional details on its stress basis comparison and justification for eliminating components. In the example, the transient section comparison resulted in two components with CUF_{en} values greater than 1.0. Using the stress basis comparison, the applicant removed the location with the lower CUF_{en} because the stress analysis method used for that component was less rigorous. The applicant stated that if this eliminated component had used a more rigorous stress analysis method, the resulting CUF_{en} would be a lower value and remain less than the retained component. The staff finds the basis reasonable that refinement using a more rigorous stress analysis method would result in lower CUF_{en} values. The staff finds the applicant's response acceptable because (1) the applicant used the stress basis comparison to only eliminate locations within a transient section with a lower screening CUF_{en} and lower stress analysis method, and (2) the applicant used the stress basis comparison to verify that the CUF_{en} values that were compared in the screening process were conservative and limiting. The staff also finds that the applicant's example demonstrated that its implementation of the stress basis comparison was reasonable in determining a bounding location for EAF monitoring during the period of extended operation. The staff's concern in RAI 4.3.4-5 is resolved. The staff finds this third step in the applicant's screening methodology, which was the stress basis comparison, appropriate as discussed above.

The fourth and final step in the screening methodology, as further detailed in the response to RAI 4.3.4-5, is to compare components that reside in different transient sections (but are within a common system or piece of major equipment) in order to determine leading locations to represent their respective system/equipment. In addition, the applicant stated that the transients themselves often control which components have the highest usage factors in a given system; so, within a particular system, those transient sections with the most severe system transients will usually have the components with the highest usage factors. However, the applicant stated that the comparison of components in different transient sections must be performed after the appropriate F_{en} correction factor is applied to the component usage factor because the F_{en} correction factor is dependent on temperature and strain rate and, therefore, can vary for each transient section.

The staff noticed that the applicant did not clarify when it compared components that reside in different transient sections, but are within a common system or piece of major equipment, to determine leading locations to represent their respective system/equipment. The staff also noticed that the applicant did not identify the assumptions or factors that were considered by the applicant when making this comparison to determine the leading location that resides in different transient sections and the basis for eliminating a location for consideration of EAF.

By letter dated February 26, 2014, the staff issued RAI 4.3.4-4 requesting the applicant to identify the locations, or a representative sample set of locations, that were compared from different transient sections, but within a common system or piece of major equipment. The staff requested that the applicant identify any components that were eliminated from the list of limiting locations and justify the basis, including any assumptions, factors or criteria that were applicable when implementing this comparison.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.4-4. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that the locations within each piping system or major equipment with a fatigue analysis were evaluated and the results were compared, and the leading locations were identified and retained. In its response, the applicant described its screening evaluation of the cold leg safety injection accumulator piping, which resides in two different transient sections. The applicant stated that for this equipment, it compared the RCL nozzle, transient section 1 check valve, valve butt weld, and transient section 2 check valve. The applicant stated that the RCL nozzle, transient section 1 check valve, and the valve butt weld are in transient section 1, and the other check valve is in transient section 2. The applicant stated that it first evaluated the three components in transient section 1 to identify the most limiting component. The applicant stated that the F_{en} screening evaluation and the stress basis comparison determined the RCL nozzle to be the most limiting component for transient section 1. The applicant then applied the same F_{en} screening evaluation and stress basis comparison to evaluate the RCL nozzle and the transient section 2 check valve. The applicant stated that these evaluations determined the RCL nozzle to be the most limiting component within the cold leg safety injection accumulator piping. The staff finds the applicant response acceptable because the applicant provided adequate detail on how its evaluation determined the limiting location within a common system or major equipment and justified the factors and criteria used in the evaluation. The staff's concerns in RAI 4.3.4-4 are resolved. The staff finds this fourth step in the applicant's screening methodology appropriate, as discussed above.

The staff finds that the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation. Additionally, the applicant's disposition meets the acceptance criteria in SRP-LR Section 4.3.2.1.3 because the applicant has demonstrated that the impact of the reactor coolant environment on critical components has been adequately addressed and will be managed by the Fatigue Monitoring Program. Therefore, the applicant's EAF evaluations will remain valid, and the ASME Code limit of 1.0 will not be exceeded during the period of extended operation, or corrective actions will be taken.

4.3.4.3 UFSAR Supplement

LRA Section A.4.3.4 provides the UFSAR supplement summarizing the effects of the reactor coolant environment on fatigue life of piping and components. The staff reviewed LRA

Section A.4.3.4, consistent with the review procedures in SRP-LR 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the reactor coolant environment on component fatigue life.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the effects of the reactor coolant environment on component fatigue life, as required by 10 CFR 54.21(d).

4.3.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has acceptably demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of EAF on the intended functions of the affected piping and components will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the EAF evaluations, as required by 10 CFR 54.21(d).

4.3.5 Reactor Vessel Internals Fatigue Analyses

4.3.5.1 Summary of Technical Information

LRA Section 4.3.5 states that the BBS RVIs were designed and procured prior to the issuance of ASME Code Section III, Subsection NG. However, the applicant stated that the intent of the code is applied at BBS with load combinations and allowable stresses, which is consistent with the requirements of ASME Code Section III, Subsection NG. The LRA states that the RVIs were designed to withstand stress originating from the same operating conditions as the reactor vessel. Using the RVI stress reports, CUFs less than 1.0 were determined for the maximum alternating stresses using the design transient cycles from each transient and the design ASME Code fatigue curve. The applicant further states that the bounding CUFs for the RVIs were evaluated for the BBS MUR power uprate project. The evaluation determined that the MUR power uprate did not affect the bounding CUFs, and therefore, no new CUFs were calculated for the MUR power uprate project. The applicant also states that the analyses performed for the RVI components are based upon a subset of the RCS design transients used in the fatigue analyses for the reactor vessel shown in LRA Tables 4.3.1-1 and 4.3.1-4.

The applicant dispositioned the TLAA for the RVIs in accordance with 10 CFR 54.21(c)(1)(iii) such that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

LRA Section 4.3.5 also states that the analyses associated with flow-induced vibrations of the RVIs are not based on time-dependent assumptions to be considered a TLAA in accordance with 10 CFR 54.3(a), Criterion 3. The applicant stated that these analyses concluded that the component stress ranges remained below the endurance limit of 10^{11} cycles on the applicable ASME fatigue curves, and therefore, the number of these stress cycles is not limited over the current operating life.

4.3.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.5 and the metal fatigue TLAAs for the RVIs to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

The staff reviewed the applicant's metal fatigue TLAAs for the RVIs and the corresponding disposition of 10 CFR 54.21(c)(1)(iii) consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The staff found that the fatigue analyses were performed using the 40-year design transients in UFSAR Table 3.9-1, which are those transients listed in LRA Tables 4.3.1-1 and 4.3.1-4 and monitored by the Fatigue Monitoring program. The applicant stated that the fatigue analyses performed for the RVIs are based upon a subset of these design transients. However, the LRA does not provide the CUF values for the RVIs. By letter December 12, 2013, the staff issued RAI B.2.1.7-4, requesting that the applicant indicate the RVI components with existing CUF analyses.

In its response dated January 14, 2014, the applicant stated that the following RVI components have existing CUF analyses: upper core plate, upper core plate alignment pins, upper support plate, baffle plate, core barrel nozzle, lower radial restraints, lower core plate, and lower support columns. The applicant also provided the CUF values and material type for each of these components. The applicant stated that the Fatigue Monitoring program will be used to monitor the transients used in the fatigue analyses of these RVI components.

The staff confirmed that the associated CUF values were all below the acceptance criteria of 1.0. The staff determined that the Fatigue Monitoring program is capable of managing metal fatigue during the period of extended operation consistent with GALL Report X.M1. The staff finds the applicant's response to RAI B.2.1.7-4 acceptable. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

The staff reviewed the staff's safety evaluation (ADAMS Accession No. ML13281A000) for the BBS MUR power uprate project. The staff noticed that the SE stated that the maximum calculated stresses and cumulative fatigue usage factor for the most limiting component of the RVIs are unaffected by the MUR and remain bounding.

The staff finds that the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue of the RVIs will be adequately managed for the period of extended operation. Additionally, the applicant's disposition meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant is crediting its Fatigue Monitoring Program to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation, otherwise, the applicant will take corrective actions in accordance with its program.

The applicant stated that analyses associated with flow-induced vibration in the RVIs are not considered a TLAA in accordance with 10 CFR 54.3(a), Criterion 3. The applicant stated that the analyses concluded that the component stress ranges remained below the endurance limit of 10^{11} cycles on the applicable ASME fatigue curves, therefore, the stress range cycles are not limited over the current operating life. The staff concluded that an analysis is only defined as a

TLAA if all six criteria outlined in 10 CFR 54.3 are satisfied. The staff reviewed the UFSAR and did not identify that the design basis for the RVIs for high-cycle fatigue depended on the licensed life of the plant period. Thus, the staff finds that all six criteria for a TLAA were not met for the applicant's evaluation of flow-induced vibration in the RVIs. Although high-cycle fatigue in the RVIs is not evaluated in the application as a TLAA, the staff found that the applicant's PWR Vessel Internals Program addresses the aging effects in the RVIs, including those that could be induced by a flow-induced vibration mechanism. The staff's evaluation of the PWR Vessel Internals Program is documented in SER Section 3.0.3.2.3. The staff further evaluated the absence of a TLAA basis for the RVI flow induced vibrations, as documented in SER Section 4.1.2.1.2.

4.3.5.3 UFSAR Supplement

LRA Section A.4.3.5 provides the UFSAR supplement summarizing the metal fatigue TLAA for the RVIs. The staff reviewed LRA Section A.4.3.5 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.3.5 meets the acceptance criteria in SRP-LR 4.3.2.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address metal fatigue TLAA for the RVIs, as required by 10 CFR 54.21(d).

4.3.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the RVIs will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.6 High-Energy Line Break (HELB) Analyses Based on Fatigue

4.3.6.1 Summary of Technical Information

LRA Section 4.3.6 states that locations of postulated HELBs are based on two limiting stress criteria and a CUF criterion, as stated in UFSAR Section 3.6. The applicant identifies the postulations of break locations based on the fatigue criterion at BBS as TLAAs. The LRA states that one of the criteria used to determine whether a HELB must be postulated at a given location is that the fatigue usage calculated for the component is greater than 0.1.

The applicant dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(iii) such that the Fatigue Monitoring program will be used to monitor transient cycles as inputs for the determination of postulated break locations and require corrective action prior to exceeding the numbers of analyzed cycles.

4.3.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.6 and the TLAAs for HELB postulations based on a CUF criterion to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging will be adequately managed during the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the applicant proposes to manage the aging effects associated with the TLAA by an AMP in the same manner as described in the integrated plant assessment (IPA) in 10 CFR 54.21(a)(3). The SRP-LR also states that the staff is to review the applicant's AMP to verify that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation. In addition, SRP-LR states that a license renewal applicant should identify the structures and components (SCs) associated with the TLAA.

UFSAR Section 3.6.2 states that high energy lines are those larger than 1 in. diameter for which the service temperature is greater than 200 °F (90 °C) or the design pressure is greater than 275 psig. The staff noticed that a given location is identified as a line break location if it was a high-energy line location that satisfied the criteria in UFSAR Section 3.6.2.1.2.1. One such criterion is that any intermediate location between terminal ends where the CUF from the piping fatigue analysis exceeds 0.1 is identified as a line break location. The staff found that the postulations of break location based on CUFs are TLAAs because they are dependent on an assumed number of cycles expected for the design of the plant. The staff concluded that UFSAR Section 3.6.2.1.1 states that the dynamic effects from postulated breaking of the reactor coolant primary piping, accumulator line piping, and reactor coolant loop bypass piping can be eliminated through the application of approved leak-before-break (LBB) technology.

The applicant credits the Fatigue Monitoring program to manage metal fatigue of these postulated HELB locations through the period of extended operation. The staff noticed that as long as the number of transients that occur at the site remain bounded by the 40-year number of cycles assumed in these analyses, the HELB postulation evaluation remains valid. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

The staff finds that the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to metal fatigue of the HELB postulated locations based on CUF will be adequately managed through the period of extended operation. Additionally, LRA Section 4.3.6 meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Fatigue Monitoring program monitors and tracks the transient cycles assumed in the analysis and requires corrective action prior to exceeding the number of transient cycles used in the analysis.

4.3.6.3 UFSAR Supplement

LRA Section A.4.3.6 provides the UFSAR supplement which summarizes the TLAA for HELB postulated locations based on CUF. The staff reviewed LRA Section A.4.3.6 consistent with the review procedures in SRP-LR-Section 4.3.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.3.6 meets the acceptance criteria in SRP-LR 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for HELB postulated locations based on CUF as required by 10 CFR 54.21(d).

4.3.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the HELB postulated locations will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.7 NRC Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification

4.3.7.1 Summary of Technical Information

NRC Bulleting 88-11, issued in December 1988, requested utilities to establish and implement a program to confirm the integrity of the pressurizer surge line. The program required both visual inspection of the surge line and demonstration that the design requirements of the pressurizer surge line are satisfied, including the consideration of stratification effects. LRA Section 4.3.7 states that BBS demonstrated consideration of thermal stratification using an ASME Code Section III fatigue analysis. Since the analysis uses time-limited assumptions, such as thermal and pressure transients, operating cycles, and the licensed life of the plant, the analyses required by NRC Bulletin 88-11 have been identified as TLAAs.

LRA Section 4.3.7 further states that pressurizer surge line stratification subtransients were developed for the original analyses. The applicant stated that the ASME Code stress limits and CUF requirements were shown to be acceptable for the current licensed life of BBS. The original analyses were evaluated for impact due to a power uprate project in 2000 and an MUR uprate in 2010. The applicant stated that these evaluations determined that the original analyses were not impacted by the uprate projects. The applicant further states that the fatigue evaluations for the components affected by this bulletin were revised to consider the baseline and projected transients in Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The LRA states that the conclusion from the analyses is that the components will continue to meet the design allowable usage of 1.0 with consideration of stratification effects during the period of extended operation.

The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii) such that the Fatigue Monitoring program will monitor the transient cycles and severities which are inputs to these analyses and require corrective action prior to exceeding design limits that would invalidate these conclusions.

4.3.7.2 Staff Evaluation

The staff reviewed LRA Section 4.3.7 and the TLAA associated with the fatigue analysis of the pressurizer surge line for thermal cycling and stratification to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff reviewed this TLAA and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR 4.3.3.1.1.3. These procedures state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

LRA Section 4.3.7 states that pressurizer surge line stratification subtransients were developed and used in the original analyses which were performed to demonstrate compliance with design requirements. However, the LRA did not include the pressurizer surge line stratification subtransients that were developed.

By letter dated February 26, 2014, the staff issued RAI 4.3.7-1, Part 1, requesting that the applicant identify the pressurizer surge line stratification subtransients that were developed.

By letter dated September 11, 2014, the applicant responded to RAI 4.3.7-1, Part 1. This letter resubmitted RAI responses originally submitted on March 28, 2014, to clarify and reduce the information previously identified as proprietary by the applicant. The applicant stated that in response to Bulletin 88-11, 11 subtransient cases were developed for the surge line piping and nine subtransient cases were developed for the surge line nozzle. The applicant stated that these subtransients were developed based on a detailed evaluation to characterize the cyclic activity during heatup and cooldown and to define a bounding set of differential temperatures. The applicant stated that the fatigue analysis for the pressurizer surge line was performed to account for the surge line pipe stratification subtransients that occur during the postulated 200 heatup and cooldown cycles. The staff finds the applicant's response to RAI 4.3.7-1, Part 1, acceptable because the applicant provided the subtransients developed in response to Bulletin 88-11 and demonstrated that these subtransients are bounded by heatup and cooldown transients that the staff confirmed will be monitored by the Fatigue Monitoring program. The staff's concern in RAI 4.3.7-1, Part 1, is resolved.

LRA Section 4.3.7 states that the fatigue evaluations for the components associated with NRC Bulletin 88-11 were revised to consider the baseline and 60-year projected transients listed in LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. The applicant stated that the fatigue usage will continue to meet the design limit of 1.0 through the period of extended operation. However, the applicant did not provide enough information on how the fatigue evaluations were revised by the LRA tables listed. By letter dated February 26, 2014, the staff issued RAI 4.3.7-1, Parts 2 and 3, requesting the applicant to identify which transients were considered when the fatigue evaluations were revised and to confirm that its Fatigue Monitoring program will adequately monitor and track the revised transients and require corrective action prior to exceeding design limits.

In the applicant's response to RAI 4.3.7-1, Parts 2 and 3, by letter dated September 11, 2014, the applicant provided the transients that were considered in the fatigue evaluations of the components affected by Bulletin 88-11. The applicant stated that the fatigue evaluations accounted for stratification effects for both heatup/cooldown transients and non-heatup/cooldown transients. The applicant stated that for the affected non-heatup/cooldown transients, stratification was assumed as the maximum applicable temperature difference for each transient cycle. The staff confirmed that the provided transients are included in the transients monitored by the Fatigue Monitoring program. The staff finds the applicant's response to RAI 4.3.7-1, Parts 2 and 3, acceptable because the applicant identified the transients that were considered in the fatigue evaluations that include the effects of thermal stratification and confirmed that the Fatigue Monitoring program will monitor the transient cycles and severities and will require action prior to exceeding design limits. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

LRA Section 4.3.7 states that the original analyses were evaluated for impact due to a power uprate project in 2000 and an MUR uprate in 2010. The applicant stated that the evaluations determined that the original analyses were not impacted by these uprate projects. The staff reviewed the staff's safety evaluation (ADAMS Accession No. ML033040016) for the BBS power uprate project in 2000. The staff noticed that the SE concluded that the fatigue usage factors for the pressurizer surge line will continue to meet the ASME Code requirements for the power uprate. The staff reviewed the staff's safety evaluation (ADAMS Accession No. ML13281A000) for the BBS MUR uprate project in 2010. The staff noticed that the SE concluded there was no adverse effect on the fatigue evaluation of the pressurizer surge line, including the effects of thermal stratification.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue analysis of the pressurizer surge line, including thermal stratification, will be adequately managed for the period of extended operation. Additionally, TLAA 4.3.7 meets the acceptance criteria in SRP-LR 4.3.2.1.1.3 because the applicant is crediting its Fatigue Monitoring program to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective action, in accordance with its program.

4.3.7.3 UFSAR Supplement

LRA Section A.4.3.7 provides the UFSAR supplement summarizing the metal fatigue TLAA for the pressurizer surge line, including thermal stratification. The staff reviewed LRA Section A.4.3.7 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.3.7 meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the pressurizer surge line, including thermal stratification, as required by 10 CFR 54.21(d).

4.3.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the pressurizer surge line, including thermal stratification, will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.8 ASME Code Section III, Subsection NF, Class 1 Component Supports Allowable Stress Analyses

4.3.8.1 Summary of Technical Information in the Application

LRA Section 4.3.8 describes the applicant's TLAA for ASME Code Section III, Subsection NF, Class 1 component supports allowable stress analyses, which include supports for the reactor vessel, steam generator, RCP, and pressurizer. The applicant stated that the BBS Class 1 component supports are inherently designed for 20,000 stress cycles of fatigue loading in accordance with the allowable stresses of ASME Code Section III, Subsection NF, 1974 edition through the 1975 summer addenda. The applicant referenced NRC-approved Westinghouse Owners Group (WOG) TR WCAP-14422, Revision 2-A, "License Renewal Evaluation: Aging Management of Reactor Coolant System (RCS) Supports," that performed a technical evaluation of cumulative fatigue aging effects on Class 1 component supports in Westinghouse reactors for the period of extended operation. The report concluded that the number of actual loading transients that affect Class 1 components is projected to be significantly less than 20,000 loading cycles for 60 years and estimated the corresponding fatigue usage to be less than 0.15, which is less than the allowable limit of 1.0. The applicant concluded that the numbers of cycles for the transients analyzed in TR WCAP-14422 are bounded by the transient limits shown in LRA Section 4.3.1. The applicant stated that the NRC Final Safety Evaluation Report, dated November 7, 2000, for TR WCAP-14422, Revision 2-A, required with regard to fatigue that each license renewal applicant justify the use of installed materials not listed in Table 2-4 of the topical report. The applicant addressed this condition by stating that its review of design documents found that the majority of installed Class 1 component support materials used were listed in WCAP Table 2-4. The applicant also stated that evaluation of several materials used that were not listed in the table showed that their yield strength and fatigue resistance properties are consistent with materials in Table 2-4 of WCAP-14422 or the materials are used in bearing plates which do not experience cyclical tensile stresses.

The applicant dispositioned the TLAA for the Class 1 component supports in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of aging due to fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The applicant stated that the Fatigue Monitoring Program in LRA Section B.3.1.1 will monitor transient cycles and require action prior to exceeding the design limits that would invalidate the conclusions of the TLAA.

4.3.8.2 Staff Evaluation

The staff reviewed the applicant's metal fatigue TLAA in LRA Section 4.3.8 related to ASME Code Section III, Subsection NF, Class 1 component supports for the reactor vessel, steam generator, RCP, and pressurizer, and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue will be adequately managed for the period of extended operation by the Fatigue Monitoring Program, consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and other transients for the selected RCS components, which in this case are the Class 1 RCS component supports.

The staff determined that LRA Section 4.3.8 references NRC-approved WOG TR WCAP-14422, Revision 2-A, "License Renewal Evaluation: Aging Management of Reactor Coolant System (RCS) Supports," as a bounding evaluation in the fatigue TLAA for the Subsection NF Class 1 component supports for the reactor vessel, steam generator, RCP, and pressurizer. In its SER dated November 17, 2000, the staff found TR WCAP-14422, Revision 2-A, acceptable for member plants to reference in an LRA to the extent specified and under the limitations delineated in the SER, which includes completing the renewal applicant action items described in Section 4.1 of the SER. SER Section 4.1, "Renewal Applicant Action Item 6 Fatigue (Section 3.3.1.7)," states that a license renewal applicant will have to justify differences between the materials used for its RCS supports and the values listed in Table 2-4 of the TR. The staff reviewed TR WCAP-14422, Revision 2-A, and confirmed that BBS was included as member operating plants to which the evaluation applies. The staff noticed that Section 3.2 of TR WCAP-14422, Revision 2-A, estimated the fatigue CUF of less than 0.15, which is less than the code allowable limit of 1.0, for 60 years of operation. This estimate was based on 300 thermal cycles (normal conditions with stress amplitude, S_a, of 30 ksi) from plant heatup and cooldown and 600 cycles (upset conditions with S_a of 50 ksi) from operating basis earthquake (OBE) seismic events for a total of 900 transient cycles, which is significantly smaller than the 20,000 cycles implicitly included in ASME Code Section III, Subsection NF design. The staff also found the applicant's statement in LRA Section 4.3.8 that the number of transients analyzed in the topical report are bounded by the transient limits shown in LRA Section 4.3.1.

From the information provided in LRA Section 4.3.8, it was not clear which specific transient limits in LRA Section 4.3.1 were considered in making the comparison to the number of transients analyzed in the WOG Report WCAP-14422. Further, the information provided in LRA Section 4.3.8 with regard to "License Renewal Applicant Action Item 6" in the NRC SER for TR WCAP-14422, Revision 2-A, was not sufficient for the staff to verify that the fatigue evaluation in the TR remains bounded for materials used in the Byron and Braidwood RCS component supports that are not listed in Table 2-4 of the TR. Therefore, by letter dated April 24, 2014, the staff issued RAI 4.3.8-1, requesting the applicant to: (1) identify the specific transient (cycle) limits in LRA Section 4.3.1 that were used in LRA Section 4.3.8 to make the comparison with the number of transients analyzed in the TR, and (2) provide a list of the materials used in the Class 1 RCS component supports that are not documented in Table 2-4 of Topical Report WCAP-14422, Revision 2-A, including information such as the yield strength, fatigue resistance properties, the component and the function of the component where the material is used, such that the staff can verify that the fatigue evaluation in the topical report remains bounding for the RCS support components using these materials.

The applicant provided its response to RAI 4.3.8-1 by letter dated May 23, 2014. In its response to the first part of the RAI 4.3.8-1, the applicant stated that three specific transients and associated cycle limits in LRA Section 4.3.1, which are same as those analyzed in the WOG Topical Report WCAP-14422, were considered in LRA Section 4.3.8. The applicant further clarified that these transients are identified in LRA Tables 4.3.1-1 and 4.3.1-4 as Transient 1, "Plant Heatup at 100 °F/hr," and Transient 2, "Plant Cooldown at 100 °F/hr," each with CLB allowable cycle limits of 200; and Transient 34 "Operating Basis Earthquake (OBE)," with a CLB allowable cycle limit of 20 OBE seismic events each with 20 subcycles for a total of 400 cycles.

The staff finds the response to the first part of RAI 4.3.8-1 acceptable because (a) the applicant clarified the transients applicable to fatigue of RCS component supports, namely cycles from plant heatup and cooldown and OBE seismic events which are the same as those deemed applicable and evaluated in TR WCAP-14422, and the corresponding allowable CLB transient limits documented in LRA Section 4.3.1, and (b) the allowable transient limits (200 plant heatup and cooldown cycles plus 400 seismic OBE cycles) in LRA Section 4.3.1 for applicable transients are bounded by the corresponding number of transient cycles (300 plant heatup and cooldown cycles plus 600 seismic OBE cycles) evaluated for 60 years of operation in TR WCAP-14422. Therefore, the staff's concern described in the first part of RAI 4.3.8-1 is resolved.

In its response to the second part of RAI 4.3.8-1, the applicant stated that BBS RCS Class 1 component supports were designed, fabricated, and installed in accordance with the requirements of ASME Code Section III, Division 1, Subsection NF, 1974 Edition with Summer 1975 addendum, using materials that conform to ASME/ASTM materials meeting the requirements of ASME Code Case 1644, "Additional Materials for Component Supports and Alternate Design Requirements for Bolted Joints Section III Division 1, Subsection NF Class, 1, 2, 3, and MC construction." The applicant further explained that, at BBS, four subcomponent types associated with RCS Class 1 component supports are constructed of materials that are not specifically documented in Table 2-4 of TR WCAP-14422 (which lists only the most commonly specified materials), and addressed the differences as summarized in SER Table 4.3.8-1 below. The applicant concluded that the information provided in the response demonstrates that the fatigue evaluation in TR WCAP-14422 is bounding for the RCS Class 1 component supports using these materials.

Table 4.3.8-1 Summary of Material Differences Addressed in RAI 4.3.8-1 Response

RCS Support Subcomponent	Material used at BBS different from Table 2-4 of TR WCAP-14422	Corresponding material listed in Table 2-4 of TR WCAP-14422 for same application	Impact of material difference on fatigue resistance properties at stress amplitude (Sa) values evaluated in TR WCAP-14422
Steam Generator Lower Lateral Support Inner Frame Structural Plates, 6.5 in. thick (UFSAR Figure 3.9-7a)	ASME SA533 Class 2 alloy steel, minimum yield strength (f_y) = 70 ksi, tensile strength (f_t) = 90-115 ksi	ASTM A588 Grade A or B LAS (f_y = 42 ksi, f_t = 63 ksi)	No impact because fatigue resistance properties (allowable loading cycles) are essentially the same based on Figure I-9.1 in Appendix I of ASME Code Section III, Division 1
Steam Generator Upper Lateral Support Snubber End-Blocks (UFSAR Figures 3.9-6 and 3.9-8)	ASME SA533 Grade B, Class 1 alloy steel (f_y = 50 ksi, f_t = 80-100 ksi), ASME SA516 Grade 70 carbon steel (f_y = 38 ksi, f_t = 70-90 ksi), or ASTM A36 carbon steel (f_y = 36 ksi, f_t = 58-80 ksi)	ASTM A572 Grade 42 LAS (f_y = 42 ksi, f_t = 60 ksi)	No impact because fatigue resistance properties (allowable loading cycles) are essentially the same based on Figure I-9.1 in Appendix I of ASME Code Section III, Division 1
Bolting	ASME SA193 Grade B7 alloy steel (f_y = 75-105 ksi, f_t = 100-125 ksi, depending on bolt size)	ASTM A354 Grade BC alloy steel (f_y = 99-109 ksi, f_t = 115-125 ksi), depending on bolt size, and ASTM A540 Grade B-23 Class 4 alloy steel (f_y = 120 ksi, f_t = 135 ksi)	No impact because fatigue resistance properties (allowable loading cycles) are essentially the same based on Figures I-9.1 and I-9.4 in Appendix I of ASME Code Section III, Division 1
Shim Plate and Spacer Materials	ASTM/ASME A36, A53, A366, A414, A569, A570, A606 Type 4, A607, and A1008 CS Type B	None listed	Fatigue aging effect not applicable since shim plates and spacers are designed for compression loads and not subject to cyclic tensile stresses and fatigue

The staff reviewed ASME Code Section III, Division 1, Appendix I, Figure I-9.1, “Design Fatigue Curves for Carbon, Low Alloy, and High Tensile Steels for Metal Temperatures Not Exceeding 700 °F,” and Figure I-9.4, “Design Fatigue Curves for High Strength Steel Bolting for Temperatures Not Exceeding 700 °F.” From these figures, for the stress amplitudes (S_a of 30 ksi and 50 ksi) evaluated in the TR, the staff confirmed that the number of allowable fatigue cycles for the materials used at BBS, as described in the table above as different from those listed in Table 2-4 of TR WCAP-14422 are essentially consistent with that for the corresponding materials listed in the Table 2-4. The staff concluded that the fatigue aging effect does not apply to the shim and spacer plates because they are subject to compressive stresses only. Therefore, the staff determines that the fatigue evaluation in TR WCAP-14422 remains bounding for the RCS support components at BBS considering the limited use of these different materials.

The staff finds the applicant’s response to the second part of RAI 4.3.8-1 acceptable because (a) the applicant provided the list and fatigue properties of the materials that are also used in some RCS support components at BBS and are different from those listed for the corresponding application in Table 2-4 of TR WCAP-14422, and (b) the information provided enabled the staff to verify that the fatigue evaluation in TR WCAP-14422 remains bounding for the RCS support components at BBS considering the limited use of these different materials. Therefore, the staff's concerns described in the second part of RAI 4.3.8-1 is resolved.

The staff finds that, although Section 3.2.6 of TR WCAP-14422 does not require identification of an AMP for fatigue, the applicant uses the Fatigue Monitoring Program to monitor RCS component supports for thermal and seismic OBE transient cycles against CLB allowable cycle limits of 200 and 400, respectively. The program requires corrective action prior to exceeding these cycle limits through the period of extended operation. The staff noticed that the enhanced Fatigue Monitoring Program is described in LRA Section B.3.1.1 as consistent with the 10 elements of X.M1 "Fatigue Monitoring" AMP in the GALL Report. The staff confirmed that supports and thermal transients were included in the program description. Also, due to the applicant's response to RAI 4.3.9-1, as discussed in SER Section 4.3.9, the staff confirmed that seismic OBE transients are also monitored by the program. The staff determined that the enhanced Fatigue Monitoring Program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.24.

The staff finds the applicant demonstrated pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging due to metal fatigue on the intended functions of the ASME Code Section III, Subsection NF, Class 1 component supports for the reactor vessel, steam generator, RCP, and pressurizer at BBS will be adequately managed for the period of extended operation.

Additionally, the TLAA meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Fatigue Monitoring Program monitors and tracks applicable transient cycles, namely plant heatup and cooldown transients and OBE seismic events, through the period of extended operation and requires corrective action prior to exceeding the CLB allowable transient limits, which bound the number of transient cycles used in the analysis, to ensure that the design CUF limit of 1.0 is not exceeded during the period of extended operation.

4.3.8.3 UFSAR Supplement

LRA Section A.4.3.8 provides the UFSAR supplement summarizing the ASME Code Section III, Subsection NF, Class 1 component supports allowable stress analyses TLAA for supports of the reactor vessel, steam generator, RCP, and pressurizer. The staff reviewed LRA Section A.4.3.8 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the staff verifies that the applicant has provided a UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA with information equivalent to that in SRP-LR Table 4.3-2.

Based on its review of the UFSAR supplement, the staff finds LRA Section A.4.3.8 meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address TLAA evaluations involving ASME Code Section III, Subsection NF, Class 1 component supports allowable stress analyses, as required by 10 CFR 54.21(d).

4.3.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue on the intended functions of the RCS Class 1 component supports for the reactor vessel, steam generator, RCP, and pressurizer will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement in LRA Section A.4.3.8 contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.9 Fatigue Design of Spent Fuel Pool Liner and Spent Fuel Storage Racks for Seismic Events

4.3.9.1 Summary of Technical Information in the Application

LRA Section 4.3.9 describes the applicant's TLAA related to fatigue design of the spent fuel pool (SFP) liner and the spent fuel storage racks for seismic events. The applicant stated that the TLAA includes a fatigue evaluation of the spent fuel storage racks (which were replaced in 2000-2001 and designed in accordance with ASME Code Section III, Subsection NF) and the SFP liner for the cyclic loads imposed by twenty (20) OBE events plus one (1) safe shutdown earthquake (SSE) event using methods similar to those for Class 1 components, in accordance with ASME Code Section III, Subsection NB. The analyses also include a fatigue evaluation of the SFP liner for the loads imposed by the new racks using the same input for seismic events. These analyses calculated a CUF of 0.95 for the spent fuel storage racks and a CUF of 0.00052 for the SFP liner, both of which are less than the allowable CUF of 1.0.

The applicant further stated that OBE events are monitored by the Fatigue Monitoring Program described in LRA Section B.3.1.1 and that no OBE or SSE events have occurred to date. The applicant also stated that the Fatigue Monitoring Program will continue to monitor OBE and SSE transient cycles, to manage fatigue of these components through the period of extended operation.

The applicant dispositioned the TLAA for Fatigue Design of SFP liner and spent fuel storage racks for seismic events in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of aging due to fatigue on the intended functions of these components will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.3.9.2 Staff Evaluation

The staff reviewed the applicant's TLAA in LRA Section 4.3.9 related to the fatigue design of SFP liner and spent fuel storage racks for seismic events and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue from seismic events will be adequately managed for the period of extended operation by the Fatigue Monitoring Program, consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical transients for the selected components, which in this case are the SFP liner and the spent fuel storage racks.

The staff also confirmed that the applicant's calculated seismic fatigue CUF values of 0.95 and 0.0052 for the spent fuel storage racks and the SFP liner, respectively, based on twenty (20) OBE events and one (1) SSE event, is less than the design code allowable of 1.0. The staff noticed that no seismic events have occurred to date at BBS, and the number of seismic events considered in the fatigue evaluation is conservative and not expected to be exceeded during the period of extended operation. Nevertheless, the staff concluded that the applicant will use its enhanced Fatigue Monitoring Program, described in LRA Section B.3.1.1, to manage aging effects due to seismic fatigue by monitoring number of occurrences of seismic transients through the period of extended operation, and the program requires corrective action prior to exceeding the number of seismic transient cycles assumed in the fatigue evaluation.

The staff also reviewed the applicant's descriptions of the enhanced Fatigue Monitoring Program, in LRA Section B.3.1.1 and LRA Section A.3.1.1, credited as the AMP in the disposition of this TLAA. From the information provided in the descriptions, it was not clear whether the scope of the applicant's Fatigue Monitoring Program included the SFP liner and spent fuel storage racks as components monitored, and load cycles from seismic events as transients monitored. Further, the LRA did not provide information with regard to the number of load cycles considered in the fatigue evaluation for each OBE and SSE event that would define the total bounding limit of seismic transients that would be monitored against by the Fatigue Monitoring Program, such that appropriate corrective action is taken before the number of seismic transient cycles assumed in the fatigue evaluation is exceeded during the period of extended operation. Therefore, by letter dated April 24, 2014, the staff issued RAI 4.3.9-1 requesting the applicant to: (1) clarify whether the LRA Section B.3.1.1, "Fatigue Monitoring" program includes under its scope (a) the SFP liner and spent fuel storage racks as components, and (b) load cycles from OBE and SSE events as parameters monitored and tracked; (2) identify the number of specific load cycles considered, in the fatigue evaluation of the spent fuel storage racks and SFP liner in LRA Section 4.3.9, for each OBE event and the SSE event. The staff also requested the applicant to update the LRA, as necessary, based on the response to RAI 4.3.9-1.

The applicant provided its response to RAI 4.3.9-1 by letter dated May 23, 2014. In its response to the first part of RAI 4.3.9-1, the applicant stated that (a) the SFP liner and the replacement spent fuel storage racks are included as "other components" within the scope of the Fatigue Monitoring program described in LRA Section B.3.1.1, and (b) the occurrence of OBE and SSE seismic transient events are monitored and tracked as parameters in the Fatigue Monitoring program. The applicant further clarified that the number of specific load cycles occurring in each seismic event are evaluated as part of the event analysis using the parameters of duration, magnitude, and cycles of the event. The applicant revised LRA Sections 4.3.9 and A.4.3.9 to clarify OBE and SSE events are monitored by the Fatigue Monitoring Program. The applicant also revised LRA Sections B.3.1.1 and A.3.1.1 to explicitly identify "other components" and seismic transients in the program description of the Fatigue Monitoring Program.

In its response to the second part of RAI 4.3.9-1, the applicant stated that the number of specific load cycles utilized in the fatigue evaluation of the replacement spent fuel storage racks and the SFP are 25 cycles for each of the 20 OBE events, and 20 cycles for the single SSE event. The applicant also revised LRA Section 4.3.9 to include this information.

The staff finds the applicant's response to RAI 4.3.9-1 acceptable because the applicant (a) clarified that the SFP liner and spent fuel storage racks are included as components, and the OBE and SSE seismic event transients are monitored under the scope of the Fatigue Monitoring program, (b) provided the total number of seismic load cycles (20 times 25 OBE load cycles plus 20 SSE cycles for a total of 520 cycles) considered in the fatigue evaluation and monitored against by the Fatigue Monitoring Program credited in the TLAA to manage the effects aging due to seismic fatigue, and (c) updated applicable LRA sections to reflect clarifying information provided in the response. Therefore, the staff's concerns described in RAI 4.3.9-1 are resolved. The staff thus determined that the enhanced Fatigue Monitoring program ensures that the number of seismic transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff's evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue from seismic events on the intended functions of the SFP liner and spent fuel storage racks at BBS will be adequately managed for the period of extended operation.

Additionally, the TLAA meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's enhanced Fatigue Monitoring Program monitors OBE and SSE seismic transient cycles and requires corrective action prior to exceeding the conservative allowable seismic transient limits used in the fatigue evaluation to ensure that the design CUF limit of 1.0 is not exceeded during the period of extended operation.

4.3.9.3 UFSAR Supplement

LRA Section A.4.3.9, as amended by letter dated May 23, 2014, provides the UFSAR supplement summarizing the TLAA for fatigue design of SFP liner and spent fuel storage racks for seismic events. The staff reviewed LRA Section A.4.3.9 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the staff verifies that the applicant has provided a UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA with information equivalent to that in SRP-LR Table 4.6-1.

Based on its review of the UFSAR supplement, as amended by letter dated May 23, 2014, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description as required by 10 CFR 54.21(d), of its actions to address TLAA evaluations involving fatigue design of SFP liner and spent fuel storage racks for seismic events.

4.3.9.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging due to fatigue from seismic events on the intended functions of the SFP liner and spent fuel storage racks will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement in LRA Section A.4.3.9 contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.10 Pressurizer Heater Sleeve Structural Assessment

4.3.10.1 Summary of Technical Information

LRA Section 4.3.10 describes plant OE regarding a leak that was discovered in the pressurizer heating element penetration sleeve number 52 during the Braidwood Unit 1 refueling outage in May 2006. The applicant stated that the failed sleeve was repaired by cutting the leaking sleeve out and installing a permanent plug in its place. The applicant stated that the design analysis for the sleeve repair plug evaluated fatigue in accordance with ASME Code Section III, Subparagraph NB-3222.4. The fatigue evaluation assumed 200 RCS heatup and cooldown transients and is, therefore, a TLAA requiring evaluation for the period of extended operation. The LRA states that based on the transient design of 200 RCS heatups and cooldowns, a CUF of a maximum 0.003 was calculated, which is below the allowable CUF value of 1.0.

The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii) such that the Fatigue Monitoring program will be used to monitor the transient cycles and require corrective action prior to exceeding design limits that would invalidate this analysis.

4.3.10.2 Staff Evaluation

The staff reviewed LRA Section 4.3.10 and the TLAA for the pressurizer heater sleeve structural assessment to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging will be adequately managed during the period of extended operation.

The staff reviewed the applicant’s TLAA and the corresponding disposition consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the applicant proposes to manage the aging effects associated with the TLAA by an AMP in the same manner as described in the IPA in 10 CFR 54.21(a)(3). The SRP-LR also states that the staff reviewed the applicant’s AMP to verify that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation. In addition, the SRP-LR requires that a license renewal applicant must identify the SCs associated with the TLAA.

The applicant credits the Fatigue Monitoring program to monitor the transient cycles and requires corrective action prior to exceeding the design limits that would invalidate this analysis. The staff reviewed LRA Tables 4.3.1-1 and 4.3.1-4, which provide the baseline and 60-year cycle projections for RCS transients and noticed that the CLB cycle limit for RCS heatup and cooldown transients are consistent with the limit assumed in the fatigue evaluation for the repair plug. Therefore, the staff determined that the transients assumed in the design analysis for the sleeve repair plug are bounded by their 60-year projection. The staff determined that the enhanced Fatigue Monitoring program ensures that the number of transients will not be exceeded during the period of extended operation or that corrective actions are taken. The staff’s evaluation of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24.

The staff finds that the applicant demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue on the intended functions of the Braidwood Unit 1 reactor coolant pressurizer heating element penetration sleeve repair will be adequately managed consistent with the CLB for the period of extended operation. Additionally, LRA Section 4.3.10 meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant’s Fatigue Monitoring program monitors and tracks the transient cycles assumed in the analysis and requires corrective action prior to exceeding the number of transient cycles used in the analysis.

4.3.10.3 UFSAR Supplement

LRA Section A.4.3.10 provides the UFSAR supplement which summarizes the Braidwood Unit 1 reactor coolant pressurizer heating element penetration sleeve repair TLAA. The staff reviewed LRA Section A.4.3.10 consistent with the review procedures in SRP-LR-Section 4.7.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.3.10 meets the acceptance criteria in SRP-LR 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the Braidwood Unit 1 reactor coolant pressurizer heating element penetration sleeve repair TLAA as required by 10 CFR 54.21(d).

4.3.10.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue on the intended functions of the Braidwood Unit 1 reactor coolant pressurizer heating element penetration sleeve repair will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification (EQ) of Electric Components

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 describes the applicant's TLAA for the evaluation of electrical equipment EQ for the period of extended operation. The applicant stated that aging evaluations for electrical components in the Byron and Braidwood EQ program that specify a qualification of at least 40 years have been identified as TLAAs for license renewal because the criteria contained in 10 CFR 54.3 are met. The applicant also stated that the Byron and Braidwood program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. The Byron and Braidwood EQ program manages applicable component thermal, radiation, and cyclic aging effects through aging evaluations for the current operating license using methods for qualification for aging and accident conditions established by 10 CFR 50.49(f). In addition, the applicant stated that 10 CFR 50.49(e)(5) requires replacement or refurbishment of components not qualified for the license term prior to the end of designated life, unless additional life is established through ongoing qualification. Further, the applicant stated that the Byron and Braidwood EQ program implemented under the requirements of 10 CFR 50.49 and the guidance of NUREG-0588 and RG 1.89 is viewed as an AMP under 10 CFR 54.21(c)(1)(iii). The applicant stated that reanalysis of an aging evaluation to extend the qualification of components is performed on a routine basis as part of the EQ program. The applicant further stated that important attributes of reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

The applicant stated that it dispositioned the Environmental Qualification (EQ) of Electric Components TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions will be adequately managed by the Environmental Qualification (EQ) of Electric Components program for components associated with the TLAA for the period of extended operation.

4.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the electric components and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.4.2.1, which state that pursuant to 10 CFR 54.21(c)(1)(iii), an applicant must demonstrate the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The EQ requirements established by 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49 specifically require each licensee to establish a program to qualify electrical equipment so that such equipment, in its end of life condition, can perform its intended function during accident conditions after experiencing the effects of inservice aging. Title 10 of the CFR

Part 49(e)(5) also requires replacement or refurbishment of components prior to the end of installed life condition (i.e., designated life) unless additional life is established through ongoing qualification. The 10 CFR 50.49 EQ program is considered an AMP for purposes of license renewal. Electric components in the applicant's EQ program with a qualification equal to or greater than the current operating term are considered a TLAA for license renewal. The Environmental Qualification (EQ) of Electric Components TLAA includes long-lived passive and active electrical and instrumentation and control (I&C) components that are important to safety and are located in a harsh environment. Harsh environments are those areas of the plant subject to the environmental effects of a LOCA, a HELB, or post-LOCA environment. EQ equipment comprises safety-related and nonsafety-related equipment, the failure of which could prevent satisfactory accomplishment of any safety-related function, and necessary operation of post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of EQ equipment. 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 4.4 and B.3.1.3, plant basis documents, additional information provided to the staff, and interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For electrical equipment, BBS uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that EQ equipment aging mechanisms and effects will be adequately managed during the period of extended operation. Per the GALL Report, plant EQ programs that implement the requirements of 10 CFR 50.49 are considered acceptable AMPs under license renewal 10 CFR 54.21(c)(1)(iii). GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components," provides an acceptable means to meet the requirements of 10 CFR 54.21(c)(1)(iii). The staff reviewed the applicant's Environmental Qualification (EQ) of Electric Components program to determine whether the electrical and I&C components covered under this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation.

The staff's evaluation focused on how the EQ program manages the aging effects to meet the requirements pursuant to 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Sections 4.4, A.4.4, B.3.1.3, and A.3.1.3 and the program basis documents. LRA Section 4.4 discusses the component reanalysis attributes, including analytical models, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions. On the basis of its audit and as described in SER Section 3.0.3.1.20, the staff finds that the EQ program, which the applicant claimed to be consistent with GALL Report AMP X.E1, "Environment Qualification (EQ) of Electric Components," is consistent with the GALL Report; therefore, the staff concludes that the applicant's Environmental Qualification (EQ) of Electric Components TLAA will be managed consistent with 10 CFR 54.21(c)(1)(iii).

Additionally, the applicant's EQ program meets the acceptance criteria in SRP-LR Section 4.4.2.1 because 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.

4.4.3 UFSAR Supplement

LRA Section A.4.4 provides the UFSAR supplement summarizing the Environmental Qualification (EQ) of Electric Components TLAA. The staff reviewed LRA Section A.4.4 and found it consistent with the review procedures in SRP-LR Section 4.4.1.3, which state that the detailed information on the evaluation of TLAAs is contained in the renewal application. A summary description of the evaluation of TLAAs for the period of extended operation is contained in the applicant's UFSAR supplement.

Based on its review of the Environmental Qualification (EQ) of Electric Components UFSAR supplement, the staff finds LRA Section A.4.4 meets the acceptance criteria in SRP-LR Section 4.4.1.3. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the Environmental Qualification (EQ) of Electric Components TLAA for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of the electric equipment will be adequately managed by the Environmental Qualification (EQ) of Electric Components AMP for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress Analysis

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 describes the applicant's TLAA for its prestressed concrete containment shell structures, each of which is made up of a cylindrical wall, a shallow dome roof, and a flat foundation slab. The LRA states that the cylindrical portion of BBS's concrete containment is prestressed by a post-tensioning system consisting of 162 vertical and 201 horizontal or hoop ungrouted tendons. The dome has three groups of ungrouted tendons with a total number of 120 (119 for Braidwood Unit 1), oriented 120° to each other and anchored at the vertical face of the dome ring. The hoop tendons are anchored at three equally spaced buttresses 240° apart, bypassing the intermediate buttress. The base foundation slab is a conventional reinforced concrete. The LRA also states that the tendons are enclosed in galvanized steel conduits filled with a corrosion protection medium. Each tendon consists of 170 high strength steel wires, each 6.35 mm (1/4 in.) in diameter.

The LRA states that the containment tendon prestressing forces are time-dependent with losses occurring due to relaxation of the steel tendons and creep and shrinkage of the concrete, which were considered in the design of the plant. The LRA also states:

> The ASME Section XI, Subsection IWL (B.2.1.30) program performs periodic surveillances of individual tendon prestressing values. Predicted lower limit (PLL) force values are calculated for each tendon prior to the surveillances to estimate the magnitude of the tendon relaxation and concrete creep and shrinkage for the given surveillance year. The prestressing forces are measured and plotted, and trend lines are developed, to ensure the average tendon group prestressing values remain above the respective minimum required values

(MRVs) until the next scheduled surveillance, and potentially for the 40-year period. The predicted lower limit force values and regression analyses, utilizing actual measured tendon forces, are used to evaluate the acceptability of the containment structure to perform its intended function over the current 40-year life of the plant, and therefore, are TLAAs requiring evaluation for the period of extended operation.

4.5.1.1 Predicted Lower Limit (PLL)

The LRA states that the initial tendon prestressing force was calculated to accommodate losses for steel tendon relaxation and concrete creep and shrinkage so that the estimated final effective tendon prestressing force at the end of 40 years would be higher than the MRVs. The LRA also states that, as part of the ASME Section XI, Subsection IWL inspections, PLL force values are calculated consistent with the guidance in RG 1.35.1, “Determining Prestressing Forces for Inspection of Prestress Concrete Containments,” for each individual tendon scheduled for examination. The LRA further states that the “actual measured values for each tendon are compared to their respective PLL values, with acceptance criteria consistent with ASME Section XI, Subsection IWL requirements.”

4.5.1.2 Regression Analysis

The LRA states that a regression analysis is developed for each of the tendon groups (hoop, dome, and vertical) to determine the trend of prestressing values of individual tendons over time. The LRA also states that the regression analysis consists of a trend line utilizing actual individual tendon prestressing forces measured during successive ASME Section XI, Subsection IWL surveillances, consistent with NRC Information Notice (IN) 99-10, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments,” Attachment 3, “Comparison and Trending of Prestressing Forces.” The LRA further states that trend lines are used to demonstrate that the prestressing forces will remain above the MRV until the next scheduled surveillance.

The LRA states that the regression analyses have been reanalyzed to extend the trend lines from 40 to 60 years by using individual tendon prestressing force values based on data incorporating the 20th and 25th year surveillances for each BBS unit. The LRA also states that the extended trend lines predict that the prestressing forces will remain above the MRVs through the period of extended operation. LRA Figures 4.5-1 through 4.5-12 contain the reanalyzed regression analyses for each tendon group. The LRA further states “[t]he Concrete Containment Tendon Prestress (B.3.1.2) program will monitor and manage the TLAAs and the associated loss of tendon prestressing forces during the period of extended operation.”

The applicant dispositioned the TLAAs for the Concrete Containment Tendon Prestress Analysis in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of tendon prestress relaxation and the associated effects of loss of prestress forces on the concrete containment prestressing system will be adequately managed by the Concrete Containment Tendon Prestress Program for the period of extended operation.

4.5.2 Staff Evaluation

The staff reviewed the applicant’s TLAA for the Concrete Containment Tendon Prestress Analysis and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.5.3.1.3, which state that the reviewer verifies that the applicant has identified the appropriate program (i.e., GALL Report AMP X.S1, "Concrete Containment Tendon Prestress") as described and evaluated in the GALL Report. The SRP-LR also states that the staff is to verify that the applicant has stated that its program contains the same program elements that the staff evaluated and relied upon in approving the corresponding generic program in the GALL Report.

The staff noticed that the SRP-LR states that the evaluation process determines that the applicant's AMP includes plant-specific OE and other relevant OE that occurred at the applicant's plant as well as at other plants. The SRP-LR also states that the applicant should consider in its AMP applicable portions of the OE with prestressing systems described in IN 99-10. The staff further noticed that the GALL Report AMP X.S1 recommends additional evaluation of the applicant's OE, which includes lift off tendon force measurements, calculations, and documentation.

The staff reviewed the UFSAR Sections 3.8.1.1.1, "Description of the Containment," 3.8.1.4.8, "Effects of Losses of Prestress," 3.8.1.7.3.2, "Inservice Tendon Surveillance Program," and Section B.3, "Post-Tensioning Tendons." The staff also reviewed statements contained in the UFSAR regarding RG 1.35, "Inservice Inspection of Ungrouted Tendons in Prestress Concrete Containments," and RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestress Concrete Containments," and confirmed that the applicant has in place a Concrete Containment Tendon Prestress Program. The staff also reviewed LRA Section B.3.1.2, "Concrete Containment Tendon Prestress," and noticed that the existing program will be enhanced for the period of extended operation. The staff's review and evaluation of LRA Section B.3.1.2, "Concrete Containment Tendon Prestress," AMP is documented in SER Section 3.0.3.2.25. During the onsite AMP audit, the staff also reviewed and evaluated the applicant's documentation regarding prestressed tendon regression analyses, surveillances, and inservice inspection (ISI) calculations, which are further discussed below.

4.5.2.1 Predicted Lower Limit (PLL)

The staff confirmed that the onsite available TLAA documentation for LRA Section 4.5, "Concrete Containment Tendon Prestress Analysis," contained calculated and actual initial seating forces (stresses), MRVs, periodic actual lift off forces, as well as predicted lift off forces (minimum design forces with upper and lower limits) for the randomly selected group tendons. The staff also confirmed that the applicant's ISI PLL calculations were developed from the loss of prestress model as discussed in RG 1.35.1. The staff further confirmed that there was an increase in the number of randomly selected tendons in the sampled groups consistent with ASME Code Section XI, Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Plants."

During its review and evaluation of LRA Section B.3.1.2, "Concrete Containment Tendon Prestress," the staff also confirmed that the applicant plans to enhance the AMP prior to the period of extended operation, so that "[f]or each surveillance interval, the predicted lower-limit, minimum required value, and trending lines will be developed for the period of extended operation as part of the regression analysis for each tendon group."

4.5.2.2 Regression Analysis

For the evaluation of the applicant's regression analysis, the staff reviewed LRA Figures 4.5-1 through 4.5-12, which contain the results of the analysis, (i.e., the trend lines, for the vertical, horizontal, and dome tendon lift off force data) and noticed that (1) some of the reported tendon groups exhibited greater control (common) tendon lift off forces in later years than those recorded at earlier periodic surveillances; (2) it was not clear whether the applicant followed the required frequency of tendon lift-off measurements of ASME Code Section XI, Subsection IWL, in the construction of the group trend lines; and (3) although LRA Section A.4.5, "Concrete Containment Tendon Prestress Analyses," (UFSAR supplement) states that trend lines, extended from 40 to 60 years, were calculated based on the most recent tendon surveillances for all three tendons groups, it was not clear to what extent this was followed. Therefore, by letter dated April 7, 2014, the staff issued RAI 4.5-1, requesting that the applicant state the cause for the recorded upward trending lift off force measurement shown in LRA Figures 4.5-1 through 4.5-12 and discuss if and how the higher values were considered and implemented when constructing the extended trend lines to 60 years of operation. In addition, the staff requested that the applicant discuss what were the selected years of measurements for the construction of the regression trend lines shown in LRA Figures 4.5-1 through 4.5-12.

In its response dated May 6, 2014, the applicant stated that "the cause of control tendons exhibiting greater lift-off forces in later years of periodic surveillances […] is consistent with factors associated with the decrease in the rate of lift-off force loss with respect to time and equipment calibration accuracy during containment tendon lift-off force measurements." The applicant referenced ASME Code Section XI, Subsection IWL-2522, "Tendon Force Elongation Measurements," which specifies that the accuracy of the equipment calibration during tendon lift-off forces examination must be within 1.5 percent of the tendon minimum ultimate strength. The applicant stated that allowable calibration variances of measuring equipment can sometimes exceed the actual amount of prestress loss predicted from one surveillance to the next for a specific tendon when there is an extended period (up to 10 years) between surveillances and the measuring equipment used has changed (e.g., different jacks and pressure gauges). The applicant further stated that, based on its review of individual control tendon data used to develop LRA Figures 4.5-1 through 4.5 12, "for all instances where control tendon reported lift-off force values were found greater in later surveillances than earlier surveillances, the difference in the reported values were within the IWL Code allowable variance associated with equipment calibration accuracy."

In regards to whether higher control tendon lift-off force data values were considered and implemented when constructing the regression trend line for each group's overall tendon prestress force losses as shown in LRA Figures 4.5-1 through 4.5-12, the applicant stated that "all control tendon lift off data values were considered and implemented," in the construction of the dome, hoop, and vertical tendon regression analysis trend lines. The applicant stated it reviewed the LRA Section 4.5 figures that reported values of increased control (common) tendons lift-off forces in later years than those recorded at earlier periodic surveillances and concluded that the increased lift-off force values had no significant effect on the affected groups' trend lines extended to 60 years of operation. The applicant also stated that the majority of the tendon lift off force losses occurred during the years 0.1 to 5 of operation (from all charts of data) and the influence of upward trending control tendon lift-off forces on tendon group trend lines becomes less significant as more data is included following future surveillances. The applicant further stated that, given the scatter in the data, none of the tendon group trend lines are dominated by any upward lift-off force measured values of the control tendons.

For the second part of RAI 4.5-1, regarding the actual surveillance years used in the construction of LRA Figures 4.5-1 through 4.5-12, the applicant stated that it included all of the individual tendon lift-off force data obtained, consistent with schedules for multi-unit sites prior to the 15th year of examination as articulated in Regulatory Position 1.5 of RG 1.35, and beginning with the 15th year examinations with those required by IWL-2421. Specifically, the applicant stated that for Byron Unit 1 and Braidwood Unit 1 the scheduled examinations were at 1, 5, 10, and 20 years, while for Byron Unit 2 and Braidwood Unit 2 they were at 1, 5, 15, and 25 years respectively, after the initial Structural Integrity Test (SIT). The applicant stated that for Braidwood additional vertical and horizontal tendon force measurements were documented for Unit 1 during the 15th year surveillance and for Unit 2 during the 3rd and 10th year surveillances. The applicant stated that these additional measurements were included in Braidwood trend line calculations for LRA Figures 4.5-7 through 4.5-10. The applicant also stated that the additional measurements at Braidwood were beyond those required by RG 1.35 and IWL-2421, and were associated with "augmented and followup examinations of tendons, (i.e., tendons affected by steam generator replacement related activities, tendons where free water inspection results did not meet acceptance criteria, tendons where the number of ineffective wires exceeded the original specified limit during construction, and tendons with excessive gaps in shim stacks)."

The staff reviewed the response to RAI 4.5-1 and noticed that the applicant attributed the increase in control tendon trend line force measurements over past successive surveillances to changes in equipment used and their calibration. The staff confirmed during the onsite audit that the applicant routinely performed equipment calibrations to ensure data consistency with measurements obtained during surveillances. Given the reported ultimate strength of the tendons provided in the applicant's response, the staff also confirmed that the recorded upward trending control tendon lift-off force measurement variance observed in LRA Section 4.5 figures is less than the ASME Code Section XI, Subsection IWL overall allowable calibration tolerance. The staff also found that, in the construction of the regression line, the influence of an upward trending control tendon lift-off force measurement is minimal because the measured value falls within the applicable group's closely clustered tendon lift-off force measurements of noncontrol tendons at each surveillance and its influence on the regression line becomes less significant over time as more data is accumulated during future surveillances. The staff also reviewed (1) a letter from NRC to Commonwealth Edison Company dated May 6, 1997 (ADAMS Accession No. ML020870515); (2) a Notice of Consideration dated December 12, 1997 (ADAMS Accession No. ML020870622); and (3) BBS TSs. Based on its review of these three documents, the staff confirmed that the applicant initially followed RG 1.35 and subsequently ASME Code Section XI, Subsection IWL, for scheduling surveillance years and that the frequency of these surveillances is consistent with the recommendations of RG 1.35, and ASME Code Section XI, Subsection IWL-2421. The staff also confirmed that LRA Figures 4.5-7 through 4.5-10 associated to Braidwood include additional lift-off force measurement data points obtained at examinations performed on 3rd, 10th, and 15th years to fulfill ASME Code Section XI, Subsection IWL repair/replacement activities, evaluations, and acceptance criteria.

The staff finds the applicant's response to RAI 4.5-1 acceptable because it clarified the cause for upward trending of tendon lift-off force measurements data recorded in LRA Figures 4.5-1 through 4.5-12 to be associated with the equipment used and its calibration and the reported values were within the ASME Code Section XI, Subsection IWL allowable variance. The staff also finds the applicant's response for the upward trending of control tendon lift-off force measurements in the construction of the trend lines acceptable because it considers their influence in the regression analysis when data is collected and plotted. The staff further finds the applicant's response regarding the years in which tendon prestress lift-off measurements were taken and accounted for in the construction of the trend lines also acceptable, because the applicant has been consistent with the applicable guidance in RG 1.35 and regulatory requirements of ASME Code Section XI, Subsection IWL. The staff's concerns described in RAI 4.5-1 are resolved.

4.5.2.3 Regression Analysis (Byron Unit 2 Only)

The staff also reviewed the onsite Byron Unit 2 regression analyses documentation consisting of two reports: (1) a report of the most recent ASME Section XI, Subsection IWL surveillance titled "Final Report for Exelon Byron Station U1 and U2 25th year Containment Building Tendon Surveillance" (IWL report) and (2) a document titled "Regression Analysis to Predict Post-Tensioning Forces for Byron Unit 2 Containment Tendons in Support of License Renewal" (license renewal analysis report). The staff compared these documents to LRA Figures 4.5-2, 4.5-4, and 4.5 6, which show that the first measurements of lift off forces for Byron Unit 2 occurred at year 1. In contrast, the staff noticed that the IWL report that contains the 60-year tendon lift off force predictions states that the evaluations started at year five. In addition, the IWL report and the license renewal analysis report appeared to differ in the number of reported tendon lift off force data points for the examined tendon groups at certain periodic surveillances. The staff, therefore, requested the applicant clarify whether there is a difference between the two reports. It was also not clear which of the two analyses was used to develop the regression analyses trend lines plotted in LRA Figures 4.5-2, 4.5-4, and 4.5-6. Therefore, by letter dated April 7, 2014, the staff issued RAI 4.5-2 requesting that the applicant clarify discrepancies in data, if any, between the IWL report and the license renewal analysis report. For any discrepancies that may exist, the staff requested the applicant provide an explanation for the differences and discuss which report was used to develop the LRA regression analyses trend lines shown in Figures 4.5-2, 4.5-4, and 4.5-6 for the period of extended operation.

In its response dated May 6, 2014, the applicant stated that in 2009, it performed the 25th year IWL examinations at Byron, including tendon lift-off force measurements for Unit 2. The results of these examinations and regression analyses for each tendon group were documented in the vendor-supplied "25th year IWL report." The applicant also stated that the additional license renewal analysis report extended the regression analyses' trend lines out to 60 years for Byron Unit 2. The applicant further stated that a review of the documents revealed differences in the content as well as in the presentation of the tendon lift-off force data; however, these differences were confirmed not to have an impact on the LRA.

The applicant stated that the difference in the surveillance year number (e.g., 1, 5, 10) between the two aforementioned documents is related to different starting dates in reporting lift off force measurements. The applicant also stated that the 25th year IWL report starts with the tendon tensioning during construction while the license renewal analysis report starts its first surveillance date approximately 4 years later (i.e., a year after the completion of the SIT consistent with RG 1.35.1, Section 4). Accordingly, the applicant stated that the 25th year IWL report documents the first surveillance as "Year 5" while the license renewal analysis report has it as "Year 1."

The applicant stated that with respect to the number of tendon lift-off force data points, a discrepancy of seven data points was identified between the two documents regarding the vertical tendon measurements in "years 1 and 5" surveillances after the SIT. The applicant also stated that this condition was entered into the CAP. The applicant further stated that it reviewed an updated 25th year surveillance graph that includes these additional lift-off values for the Unit 2 vertical tendon group and found no appreciable impact to the trend line at later years, especially for years 40 to 60, since the missing data was from "years 1 and 5" and were of approximately of the same force values as other data points in those surveillance years. Furthermore, the applicant stated that the 60-year regression analysis trend line developed for the LRA included these additional lift-off values and has been shown to remain above the MRV.

Regarding which of the two reports' data sets were used to develop LRA Figures 4.5-2, 4.5-4, and 4.5-6 and the resulting tendon prestress trend lines extending to 60-year of operation, the applicant stated that the data set contained in the license renewal analysis report was used. The applicant also stated the license renewal analysis report is more representative of the loss of prestress because it contains additional tendon lift-off force data points. The applicant also stated that use of the license renewal analysis report data set is appropriate because the surveillance year numbers are presented consistent with ASME Code Section XI, Subsection IWL-2400, which prescribes the examination frequency years relative to the completion of the SIT.

The staff reviewed the response to RAI 4.5-2 and noticed the clarification that year 1 in the license renewal analysis report corresponds to year 5 of the 25th year IWL report as the initial surveillance following the SIT. The staff finds that the surveillance frequencies after the completion of the SIT, as used in the license renewal analysis report and per RG 1.35.1, are the appropriate years to be used in the regression analyses and construction of the trend lines. The staff concluded that no further clarification or action is necessary for this apparent discrepancy. The staff also determined that the applicant also identified the variance in the two reports regarding the number of reported vertical tendons lift-off force measurements for the first two surveillances following completion of the SIT. The staff noticed that the applicant addressed the issue within the CAP and concluded that no further action was required since the missing data, once evaluated and included in the regression analysis, was "found to have no appreciable impact on the trend line" slope during the period of extended operation. Moreover, the staff noticed that the applicant also investigated the LRA figures of concern and concluded that the regression trend lines were a function of all available points past the completion of the SIT. The staff finds the applicant's response acceptable because (1) the applicant clarified the reasons for the discrepancies in the listed years of ISI surveillances and the number of lift-off data points between the 25th year IWL report and the license renewal analysis report, and confirmed that there was no impact on the analyses for license renewal; and (2) the applicant confirmed that the appropriate document was used for the construction of LRA Figures 4.5-2, 4.5-4, and 4.5-6. The staff's concerns described in RAI 4.5-2 are resolved.

Following the review and assessment of PLL and regression analyses (trend lines) methodologies for the evaluation of the TLAA components, above, the staff confirmed that these are consistent with the recommendations provided in GALL Report AMP X.S1. The staff also noticed that the applicant plans to use its enhanced Concrete Containment Tendon Prestress AMP to manage the loss of tendon prestressing forces during the period of extended operation; the program is evaluated in SER Section 3.0.3.2.25.

The staff finds that the applicant demonstrated pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of tendon prestress relaxation and the associated effects of loss of prestress forces on the containment structure prestressing system will be adequately managed for the period of extended operation.

Additionally, LRA Section 4.5 meets the acceptance criteria in SRP-LR Section 4.5.2.1.3, because the applicant has in place an AMP proposed to be enhanced prior to the period of extended operation so that it can adequately manage the effects of loss of tendon prestressing forces.

4.5.3 UFSAR Supplement

LRA Section A.4.5 provides the UFSAR supplement summarizing the concrete containment tendon prestress TLAA. The staff reviewed LRA Section A.4.5 consistent with the review procedures in SRP-LR Section 4.5.3.2, which state that the reviewer verifies that the applicant has provided an UFSAR supplement, that includes a summary description of the evaluation of the concrete containment tendon prestress TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.5 meets the acceptance criteria in SRP-LR Section 4.5.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the PLL and regression analyses (trend lines) of the TLAA associated with predictions of containment tendon prestress losses, as required by 10 CFR 54.21(d).

4.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of loss of tendon prestressing forces on the intended function of the concrete containment will be adequately managed by the Concrete Containment Tendon Prestress AMP during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses

LRA Section 4.6 states that the Byron and Braidwood prestressed concrete containment structures each include leak-tight liners (membranes) made from welded carbon steel plates, attached to the entire inside surface of the concrete structure. The LRA also states that each prestressed concrete containment structure and the portion of the carbon steel liner backed by concrete were designed to conform to the ASME Code Section III, Division 2 requirements to withstand design-basis accident pressures. The LRA further states that the containment structure design includes Class MC components (emergency personnel airlocks, equipment access hatches and integral personnel airlocks, and all associated penetrations and nozzles), which are designed in accordance with ASME Code Section III, Division 1, requirements.

LRA Section 4.6 provides the applicant's analyses of the following:

- containment liner plates fatigue
- containment airlocks and hatches fatigue
- containment electrical penetrations fatigue
- containment piping penetrations fatigue
- fuel transfer tube bellows fatigue
- recirculation sump guard piping bellows fatigue

4.6.1 Containment Liner Plates Fatigue

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6.1 describes the applicant's TLAA for containment liner plates fatigue. The LRA states that the portion of the liner that is backed by concrete was designed in accordance with the 1973 Edition of ASME Code Section III, Division 2, Subarticles CC-2500, CC-4500, and CC-5500, and required that the liner be analyzed for the effects of cyclic loading to satisfy the requirements of the 1973 Edition of ASME Code Section III, Division 1, Subsection NE. The LRA also states that the original design analysis, based on 40-year design inputs, justified that the liner meets the six "exemption criteria" specified in ASME Code Section III, Subparagraph NE-3222.4(d) below, and that no fatigue analysis was required:

(1) atmospheric-to-operating pressure cycles
(2) normal operation pressure fluctuations
(3) temperature difference—startup and shutdown
(4) temperature difference—normal operation
(5) temperature difference—dissimilar materials
(6) mechanical loads

The LRA states:

> …a re-evaluation of the design inputs was performed relative to the six criteria, and it determined that the original inputs remain valid. The temperature differences have not changed because the design transients have not been redefined. The 60-year transient projections provided in Section 4.3.1 show that the transient limits will not be exceeded during the period of operation. Therefore, the numbers of temperature and pressure cycles considered in determining the components were exempt from fatigue analysis will not be exceeded. The Fatigue Monitoring (B.3.1.1) Program will be used to monitor the applicable cycles and ensure that the transient limits will not be exceeded during the period of extended operation.

The applicant dispositioned the TLAA for the containment liner plates in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the containment liner plates and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function of the liner plates will be adequately managed by the Fatigue Monitoring Program. The staff reviewed the applicant's TLAA and its disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which state that the applicant's proposed AMP is reviewed to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation.

The staff also reviewed ASME Code Section III, Subparagraph NE-3222.4(d), to ensure that the design inputs considered in the original analysis, which met the conditions for components not requiring analysis for cyclic operation, would continue to meet the conditions for a fatigue waiver, based on the 60-year transient projections in LRA Section 4.3.1. The staff concluded that the applicant's Fatigue Monitoring Program, with enhancements, will monitor transient cycles to ensure that transient limits considered in the original design analysis are not exceeded during the period of extended operation. However, based on the staff's review of the 60-year cycle projections for transients in LRA Section 4.3.1 and UFSAR Section 3.9.1.1, "Design Transients," the staff did not have sufficient information to determine which transients were considered in the original design analysis. To verify that the transients considered in the ASME NE-3222.4(d) analyses will be monitored by the Fatigue Monitoring Program and that the applicable cycles are clearly identified so that they will not be exceeded during the period of extended operation, the staff issued RAI 4.6.1-1 by letter dated April 24, 2014. With respect to the six design inputs to the "exemption criteria" meeting the conditions of ASME Code Section III, Division 1, Subparagraph NE-3222.4(d), through RAI 4.6.1-1, the staff requested that the applicant (1) indicate which transients were considered in each of the TLAAs described in LRA Sections 4.6.1, 4.6.2, and 4.6.3; and (2) provide the number of transient cycles that were assumed in the original design analyses, as well as the number of additional cycles anticipated for LRA Sections 4.6.1, 4.6.2, and 4.6.3 during the period of extended operation.

In its response dated May 23, 2014, the applicant stated:

> [t]he verification that the conditions are met is dependent on the specified number and magnitude of pressure and temperature transients and mechanical load cycles. These assumed inputs are then used to assess the potential effect on the component and consideration of other limitations to determine if the fatigue waiver can be applied. The original design specifications provided the expected number and magnitude of pressure and temperature transients and mechanical load cycles to be considered for the fatigue waiver in the original design analysis…

In its response, the applicant also provided a table relating each of the "exemption conditions" considered in the fatigue waiver to the corresponding LRA transients. The applicant clarified that, for condition 2, the normal operation pressure fluctuations condition is not considered in the LRA Section 4.3.1 tables and is not monitored by the Fatigue Monitoring Program because the pressure fluctuations during normal operation are insignificant. The applicant stated that the projected maximum number of cycles for a Type A leak test are 15, and hence are insignificant when compared to the 2,500 cycles assumed in the design analysis of the liner.

Additionally, the applicant stated that "for conditions 4 and 5, it was conservatively interpreted that the temperature differences could be the result of not only heatups and cooldowns, but also upset conditions. Therefore […], a number of transients were associated with these two conditions." The applicant further stated that "there were no additional cycles, above those used as inputs for the exemption, anticipated for component analyses in LRA Section 4.6.1, 4.6.2, and 4.6.3 during the period of extended operation" and that "[t]he current license basis (CLB) cycle limits are equal to or bounded by the fatigue exemption cycles assumed in the original design analysis."

The staff reviewed the applicant's fatigue "exemption" assessment documented in Table 1, "Byron and Braidwood Units 1 and 2 Fatigue Exemption Inputs Assessment," of the response to RAI 4.6.1-1 and noticed that, for conditions (1) and (3)–(5) of ASME Code Section III, Division 1, Subparagraph NE-3222.4(d), considered in the fatigue waiver, the 60-year cycle projections from LRA Tables 4.3.1-1 and 4.3.1-4 based on the corresponding LRA transients are significantly less than the numbers assumed in the original design analysis, and are bound by the CLB cycle limits provided in LRA Tables 4.3.1-1 and 4.3.1-4. The staff also noticed that for condition (2), the normal operating pressure fluctuations are considered insignificant and, for condition (6), there were no significant mechanical load fluctuations considered on the liner in the original design specification.

The staff finds the applicant's response acceptable because the information in the RAI response provided sufficient information to verify that the design transient cycles considered in the fatigue waiver analysis for the containment liner plates are included in LRA Section 4.3 and will be monitored by the Fatigue Monitoring Program, to ensure that the bounding transient limits will not be exceeded during the period of extended operation. The staff's concern described in RAI 4.6.1-1 is resolved.

Further, the staff reviewed LRA Section B.3.1.1 and noticed that the applicant's Fatigue Monitoring Program, with enhancements, monitors and tracks critical thermal and pressure transients and that:

> [t]he fatigue cycle monitoring data was used to project the numbers of cycles that will occur during 60 years. These projections show that the current 40-year allowable cycle limits will not be exceeded in 60 years. Therefore, the current 40-year cycle limits will be maintained for the period of extended operation. The Fatigue Monitoring aging management program will be enhanced to monitor additional plant transients that are significant contributors to cumulative fatigue damage.

The staff's review and evaluation of the applicant's enhanced Fatigue Monitoring Program is documented in SER Section 3.0.3.2.24.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment liner plates will be adequately managed for the period of extended operation.

Additionally, the Fatigue Monitoring Program meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the Fatigue Monitoring Program will monitor transient cycles to ensure that, if a transient limit is approached, corrective action will be taken prior to exceeding a transient limit, ensuring that the "exempt conditions" in ASME Code Section III, Subparagraph NE-3222.4(d), continue to be met for components not requiring fatigue analysis for cyclic operation during the period of extended operation.

4.6.1.3 UFSAR Supplement

LRA Section A.4.6.1 provides the UFSAR supplement summarizing the TLAA for the containment liner plates fatigue. The staff reviewed LRA Section A.4.6.1 consistent with the review procedures in SRP-LR Section 4.6.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the containment liner plates fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds LRA Section A.4.6.1 meets the acceptance criteria in SRP-LR Section 4.6.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue monitoring of containment liner plates, as required by 10 CFR 54.21(d).

4.6.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment liner plates will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.2 Containment Airlocks and Hatches Fatigue

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.2 describes the applicant's TLAA for containment airlocks and hatches fatigue. The LRA states that Byron and Braidwood emergency personnel airlock, personnel airlock with equipment hatch, and all penetrations and nozzles associated with personnel airlocks were designed as Class MC components in accordance with the 1971 Edition of ASME Code Section III, Subsection NE, through the Summer 1973 Addenda. The LRA also states that the original design analyses for containment Class MC components, based on 40-year design inputs, justified that these components meet the six "exemption criteria" specified in ASME Code Section III, Subparagraph NE-3222.4(d), below and that no fatigue analysis was required.

(1) atmospheric-to-operating pressure cycles
(2) normal operation pressure fluctuations
(3) temperature difference—startup and shutdown
(4) temperature difference—normal operation
(5) temperature difference—dissimilar materials
(6) mechanical loads

The LRA also states that:

> …a re-evaluation of the design inputs was performed relative to these criteria from ASME Section III, Subparagraph NE-3222.4(d). The results of the re-evaluation determined that the original inputs remain valid. The temperature differences have not changed because the design transients have not been redefined. The 60-year transient projections provided in Section 4.3.1 show that the transient limits will not be exceeded during the period of extended operation. Therefore, the number of temperature and pressure cycles considered in determining the components, which were exempt from fatigue analysis, will not be exceeded. The Fatigue Monitoring (B.3.1.1) Program will be used to monitor the applicable cycles and ensure that the transient limits will not be exceeded during the period of extended operation.

The applicant dispositioned the TLAA for the containment airlocks and hatches in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.2.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the containment airlocks and hatches and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function of the containment airlocks and hatches will be adequately managed by the Fatigue Monitoring Program. The staff reviewed the applicant's TLAA and disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which state that the applicant's proposed AMP is reviewed to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation.

The staff also reviewed ASME Code Section III, Subparagraph NE-3222.4(d), to ensure that the design inputs considered in the original analysis, which met the conditions for components not requiring analysis for cyclic operation, would continue to meet the conditions for a fatigue waiver, based on the 60-year transient projections in LRA Section 4.3.1. The staff noticed that the applicant's Fatigue Monitoring Program, with enhancements, will monitor transient cycles to ensure that transient limits considered in the original design analyses are not exceeded during the period of extended operation.

The staff requested additional information through RAI 4.6.1-1 regarding the applicable transients and cycle limits considered in the original fatigue waiver analyses for the containment class MC components (i.e., the emergency personnel airlock, the personnel airlock with equipment hatch, and all the penetrations and nozzles associated with personnel airlocks). The staff's discussion and evaluation of the applicant's response to RAI 4.6.1-1 is documented in SER Section 4.6.1.2. The applicant provided a fatigue exemption input assessment table demonstrating that the total 60-year cycle projections from LRA Tables 4.3.1-1 and 4.3.1-4 for the LRA transients corresponding to the ASME Code Section III, Division 1, Subparagraph NE-3222.4(d), conditions would not exceed the number of cycles assumed in the original design analysis for the evaluated containment class MC components and are bound by the CLB cycle limits provided in LRA Tables 4.3.1-1 and 4.3.1-4. The information in the RAI response provided sufficient information for the staff to verify that the design transient cycles considered in the fatigue waiver analysis for the containment airlocks and hatches are included in LRA Section 4.3 and will be monitored by the Fatigue Monitoring Program to ensure that the bounding transient limits will not be exceeded during the period of extended operation.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment airlocks and hatches will be adequately managed for the period of extended operation.

Additionally, it meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the Fatigue Monitoring Program will monitor transient cycles to ensure that, if a transient limit is approached, corrective action will be taken prior to exceeding a transient limit, ensuring that the "exempt conditions" in ASME Code Section III, Subparagraph NE-3222.4(d), continue to be met for components not requiring fatigue analysis for cyclic operation during the period of extended operation.

4.6.2.3 UFSAR Supplement

LRA Section A.4.6.2 provides the UFSAR supplement summarizing the TLAA for containment airlocks and hatches fatigue. The staff reviewed LRA Section A.4.6.1 consistent with the review procedures in SRP-LR Section 4.6.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds LRA Section A.4.6.2 meets the acceptance criteria in SRP-LR Section 4.6.2.2, and is therefore acceptable. Additionally, the staff concludes that the applicant has provided an adequate summary description of its actions to address the fatigue monitoring of containment airlocks and hatches, as required by 10 CFR 54.21(d).

4.6.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment airlocks and hatches will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.3 Containment Electrical Penetrations Fatigue

4.6.3.1 Summary of Technical Information in the Application

LRA Section 4.6.3 describes the applicant's TLAA for containment electrical penetrations fatigue. The LRA states that Byron and Braidwood prestressed concrete containment structures include electrical penetrations that were designed in accordance with the ASME Code Section III, Division 1, Subsection NE, 1977 Edition through Summer 1978 Addenda requirements. The LRA also states that the original design analysis for containment electrical penetrations, based on 40-year design inputs, justified that these components meet the six "exemption criteria" specified in ASME Code Section III, Subparagraph NE-3222.4(d), below and that no fatigue analysis was required.

(1) atmospheric-to-operating pressure cycles
(2) normal operation pressure fluctuations
(3) temperature difference—startup and shutdown
(4) temperature difference—normal operation
(5) temperature difference—dissimilar materials
(6) mechanical loads

The LRA further states that:

> …a re-evaluation of the design inputs was performed relative to the six criteria, and it determined that the original inputs remain valid. The temperature differences have not changed because the design transients have not been redefined. The 60-year transient projections provided in Section 4.3.1 show that the transient limits will not be exceeded during the period of extended operation. Therefore, the number of temperature and pressure cycles considered in determining the components, which were exempt from fatigue analysis, will not be exceeded. The Fatigue Monitoring (B.3.1.1) Program will be used to monitor the applicable cycles and ensure that the transient limits will not be exceeded during the period of extended operation.

The applicant dispositioned the TLAA for the containment electrical penetrations in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.3.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the containment electrical penetrations and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function of the containment electrical penetrations will be adequately managed by the Fatigue Monitoring Program. The staff reviewed the applicant's TLAA and disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which state that the applicant's proposed AMP is reviewed to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation.

The staff also reviewed ASME Code Section III, Subparagraph NE-3222.4(d), to ensure that the design inputs considered in the original analysis, which met the conditions for components not requiring analysis for cyclic operation, would continue to meet the conditions for a fatigue waiver, based on the 60-year transient projections in LRA Section 4.3.1. The staff noticed that the applicant's Fatigue Monitoring Program, with enhancements, will monitor transient cycles to ensure that design limits considered in the original design analyses are not exceeded during the period of extended operation.

The staff requested additional information through RAI 4.6.1-1 regarding the applicable transients and cycle limits considered in the original fatigue waiver analyses for the containment electrical penetrations. The staff's discussion and evaluation of the applicant's response to RAI 4.6.1-1 is documented in SER Section 4.6.1.2. The applicant provided a fatigue exemption input assessment table demonstrating that the total 60-year cycle projections from LRA Tables 4.3.1-1 and 4.3.1-4 for the LRA transients corresponding to the ASME Code Section III, Division 1, Subparagraph NE-3222.4(d), conditions would not exceed the number of cycles assumed in the original design analysis for the evaluated containment class MC components and are bound by the CLB cycle limits provided in LRA Tables 4.3.1-1 and 4.3.1-4. The information in the RAI response provided the staff sufficient information to verify that the design transient cycles considered in the fatigue waiver analysis for the containment electrical penetrations are included in LRA Section 4.3 and will be monitored by the Fatigue Monitoring Program to ensure that the bounding transient limits will not be exceeded during the period of extended operation.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment electrical penetrations will be adequately managed for the period of extended operation.

Additionally, LRA Section 4.6.3 meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the Fatigue Monitoring Program will monitor transient cycles to ensure that, if a transient limit is approached, corrective action will be taken prior to exceeding a transient limit, ensuring that the "exemption conditions" in ASME Code Section III, Subparagraph NE-3222.4(d), continue to be met for components not requiring fatigue analysis for cyclic operation during the period of extended operation.

4.6.3.3 UFSAR Supplement

LRA Section A.4.6.3 provides the UFSAR supplement summarizing the TLAA for containment electrical penetrations fatigue. The staff reviewed LRA Section A.4.6.1 consistent with the review procedures in SRP-LR Section 4.6.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds LRA Section A.4.6.3 meets the acceptance criteria in SRP-LR Section 4.6.2.2 and is therefore acceptable. Additionally, the staff concludes that the applicant has provided an adequate summary description of its actions to address the fatigue monitoring of containment electrical penetrations, as required by 10 CFR 54.21(d).

4.6.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment electrical penetrations will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.4 Containment Piping Penetrations Fatigue

4.6.4.1 Summary of Technical Information in the Application

LRA Section 4.6.4 describes the applicant's TLAA for the containment piping penetrations fatigue. The LRA states the Byron and Braidwood containment structure penetrations conform to the requirements of ASME Code Section III, Subsection NE, 1971 Edition through the Summer 1973 Addenda. The LRA also states that the instrument and process pipe penetrations required fatigue evaluation of each containment structure penetration, in accordance with ASME Code Section III, Subparagraph NB-3222.4(e) or NE-3222.4(e).

The LRA further states that:

> [t]he design specifications for the containment piping penetrations define the transients applicable to penetration stress analysis. These same transients are listed in Section 4.3.1, along with the 60-year projections.… The Fatigue Monitoring (B.3.1.1) Program is used to monitor the applicable transients and ensure that transient limits are not exceeded. The program also ensures that, if a transient limit is approached, corrective action is taken to reanalyze components prior to exceeding a transient limit.

The applicant dispositioned the TLAA for the containment piping penetrations fatigue in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

4.6.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the containment piping penetrations and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function of the containment piping penetrations will be adequately managed by the Fatigue Monitoring Program. The staff reviewed the applicant's TLAA and disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which state that the applicant's proposed

AMP is reviewed to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation.

The staff also reviewed ASME Code Section III, Subparagraphs NB-3222.4(e) and NE-3222.4(e), by which a fatigue evaluation was performed for the containment piping penetrations. In its review of UFSAR Section 3.8.2, "Steel Containment and ASME Class MC Components," the staff noticed that penetration sleeves are described as being designed as Class MC components in accordance with Subsection NE of the ASME B&PV Code, Section III, which are directly exposed to worst case loading conditions of the process piping. The head fittings are designed in accordance with Subsection NB, NC, or ND of the ASME Code, Section III, as applicable. The staff also noticed that the fatigue loading conditions include thermal and pressure load transients as well as those of OBE and other mechanical loads. However, it was not clear which of the transients listed in LRA Section 4.3.1 were considered in the analyses of penetration sleeves. Therefore, by letter dated April 24, 2014, the staff issued RAI 4.6.4-1, requesting that the applicant identify the applicable transients, including the cycle limit for each transient, assumed in the fatigue analysis for the containment piping penetrations.

In its response dated May 23, 2014, the applicant provided two tables. One table correlated the containment piping penetration analyses assumed transients and limits to the LRA RCS transients and limits contained in LRA Tables 4.3.1-1 and 4.3.1-4. The other table correlated the containment piping penetration analyses assumed transients and limits to the LRA auxiliary system transients and limits contained in LRA Tables 4.3.1-2 and 4.3.1-5. The applicant stated that the tables:

> …document the pressure and temperature transients and the number of cycles that were assumed in the fatigue analyses for the containment piping penetrations, and also document the corresponding transient number and CLB cycle limits for LRA Tables 4.3.1-1, 4.3.1-2, 4.3.1-4, and 4.3.1-5. These fatigue analyses also applied loads associated with operating basis earthquakes (OBE) in combination with loads created by the pressure and temperature transients.

The applicant also stated that the transients and cycle limits documented in the tables, provided in response to RAI 4.6.4-1:

> …reflect what was assumed in the original fatigue analysis for the containment piping penetrations, are currently monitored by the Fatigue Monitoring aging management program implementing procedures, and will continue to be monitored during the period of extended operation.

The applicant further stated the that main steam and feedwater containment piping penetration analyses were inconsistent with the Westinghouse transient design specifications, and sufficient margin in the original analysis existed such that a corrective action is being taken to revise the analyses to increase the number of cycles to the CLB limits of LRA Tables 4.3.1-1 and 4.3.1-4.

The staff reviewed the applicant's Table 1, "Correlation of Containment Piping Penetration Analyses Assumed Transients and Limits to LRA RCS Transients and Limits Contained in LRA Tables 4.3.1-1 and 4.3.1-4." The LRA states that the applicant's Fatigue Monitoring Program will monitor the transients to the CLB cycle limits; however, a reanalysis needs to be made for the main steam and feedwater containment piping penetrations to "increase the number of cycles to the original CLB cycle limits." The staff confirmed that UFSAR Section 3.9.1.1, "Design Transients," does specify 13,200 cycles for the "Unit Loading and Unloading at

5 percent of Full Power per Minute" transient, which would apply to the associated penetration piping. The staff concluded that the corrective action being taken to revise the main steam and feedwater piping penetration analyses to be consistent with the governing Westinghouse transient design specifications, which the applicant determined had sufficient margin to accommodate the change, is appropriate. In addition the staff concluded that the applicant revised the LRA to indicate that faulted and emergency condition transients and limits are monitored for the RCS through its Fatigue Monitoring Program.

The staff also reviewed Table 2, "Correlation of Containment Piping Penetration Analyses Assumed Transients and Limits to LRA Auxiliary System Transients and Limits Contained in LRA Tables 4.3.1-1 and 4.3.1-4," and noticed that the limits considered in the analyses were either greater than the CLB cycle limits or no longer relevant (e.g., because of changes in the chemistry sampling strategy leading to a reduction in the originally considered number of thermal cycles); and therefore, the staff finds these limits acceptable.

The staff finds the applicant's response acceptable because the information in the RAI response provided the staff sufficient information to verify that the design transient cycles, considered in the fatigue evaluation for each containment piping penetration, are included in LRA Section 4.3 and will be monitored by the Fatigue Monitoring Program, to ensure that the bounding transient limits will not be exceeded during the period of extended operation. The staff's concern described in RAI 4.6.4-1 is resolved.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment piping penetrations will be adequately managed for the period of extended operation.

Additionally, LRA Section 4.6.4 meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the Fatigue Monitoring Program will monitor transient cycles to ensure that, if a transient limit is approached, corrective action is taken prior to exceeding a transient limit.

4.6.4.3 UFSAR Supplement

LRA Section A.4.6.4 provides the UFSAR supplement summarizing the TLAA for containment piping penetrations fatigue. The staff reviewed LRA Section A.4.6.4 consistent with the review procedures in SRP-LR Section 4.6.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.6.2.2 and is therefore acceptable. Additionally, the staff concludes that the applicant provided an adequate summary description of its actions to address fatigue of containment piping penetrations, as required by 10 CFR 54.21(d).

4.6.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the containment piping penetrations will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.5 Fuel Transfer Tube Bellows Fatigue

4.6.5.1 Summary of Technical Information in the Application

LRA Section 4.6.5 describes the applicant's TLAA for fuel transfer tube bellows fatigue. The LRA states that the fuel transfer tubes pass through the containment structure, connecting the refueling cavity to the fuel transfer canal inside the fuel handling building and that the guard pipe assemblies for the fuel transfer tubes also function as penetration sleeves. The LRA also states that there are three expansion bellows in the penetration sleeve around each fuel transfer tube, and three sets of expansion joints (bellows) for the 24-in.-diameter penetration sleeves that comprise the guard pipes for the fuel transfer tubes. The LRA states that the design specification considered 100 load cycles, based on ASME Code Section III, Subsection NE and qualified per Subparagraph NE-3365.2(e)(2), 1974 Edition through Summer 1974, "along with the maximum displacements intended to envelope all postulated design-basis conditions, including 1 Safe Shutdown Earthquake (SSE) transient event, for fatigue consideration."

The LRA also states that:

> [t]hese bellows are affected by seismic transients (1 SSE event) that would cause deflection of the bellows. These transients are listed in Section 4.3.1 and have 60-year projections that are less than the numbers of cycles which form the basis for the design requirement of 100 design load cycles and used for the qualification of bellows. Therefore, the qualification of the bellows is acceptable for the period of extended operation. The Fatigue Monitoring (B.3.1.1) Program monitors SSE transient events.

The applicant dispositioned the TLAA for the fuel transfer tube bellows in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the fuel transfer tube bellows and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function of the fuel transfer tube bellows will be adequately managed by the Fatigue Monitoring Program. The staff reviewed the applicant's TLAA and disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which state that the applicant's proposed AMP is reviewed to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation.

The staff also reviewed ASME Code Section III, Subparagraph NE-3365.2(e)(2), by which the fuel transfer tube bellows were qualified. The staff noticed that LRA Section 4.6.5 states that these bellows are limited to 100 design load cycles and the maximum displacements, including one SSE event, which would cause deflection of the bellows, and that the transient cycle projections listed in Section 4.3.1 are fewer than the number of cycles which forms the basis for the design requirement. However, the transients listed in LRA Section 4.3.1 do not include the SSE event. It was not clear that the Fatigue Monitoring Program is monitoring the SSE event to support the applicant's claim that the effects of aging on the fuel transfer tube bellows will be adequately managed by the Fatigue Monitoring Program. Therefore, by letter dated April 24, 2014, the staff issued RAI 4.6.5-1, requesting that the applicant identify what transients along with maximum displacements, other than those associated with SSE, have been considered in the fuel transfer tube bellows fatigue analysis, provide the number of cycles assumed in the design, and clarify why the SSE transients are not listed in the tables in LRA Section 4.3.1.

In its response dated May 23, 2014, the applicant stated that:

> [t]he SSE and LOCA events are the only transients considered in the analysis for the fuel transfer bellows. As described in LRA Section 4.6.5, TLAA Description, the 100 design load cycles envelope the postulated design-basis conditions. Therefore, there are no other transients associated with the analysis. The maximum displacements specified were 1.75 inches axially and 0.5 inches laterally. The Fatigue Monitoring Program monitors and tracks SSE and LOCA events. If a seismic event occurs, the program reviews the duration, magnitude, and number of cycles of the event….

The applicant revised LRA Section A.3.1.1 and B.3.1.1 to clarify that the Fatigue Monitoring Program manages the cumulative fatigue damage of “other components” and monitors design-basis events and counts them in the appropriate design transient category. The applicant also clarified that SSE and LOCA are one-time, faulted events monitored by the current Fatigue Monitoring Program, not normal inputs to fatigue monitoring. Therefore, the SSE and LOCA events are not listed in LRA Tables 4.3.1-1 through 4.3.1-6.

The staff finds the applicant’s response acceptable because the Fatigue Monitoring Program, with enhancements, monitors seismic events including duration, magnitude, and number of cycles, and LOCA events to ensure that, if the maximum displacements due to an SSE or LOCA event are exceeded, corrective action is taken. The staff’s evaluation of the Fatigue Monitoring Program and acceptability of the enhancements is documented in SER Section 3.0.3.2.24. The staff’s concern described in RAI 4.6.5-1 is resolved.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the fuel transfer tube bellows will be adequately managed for the period of extended operation.

Additionally, LRA Section 4.6.5 meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the Fatigue Monitoring Program will monitor transient cycles to ensure that, if a transient limit is approached, corrective action is taken prior to exceeding a transient limit.

4.6.5.3 UFSAR Supplement

LRA Section A.4.6.5 provides the UFSAR supplement summarizing the TLAA for fuel transfer tube bellows fatigue. The staff reviewed LRA Section A.4.6.5 consistent with the review procedures in SRP-LR Section 4.6.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, as amended by letter dated May 23, 2014, the staff finds that LRA Section A.4.6.5 meets the acceptance criteria in SRP-LR Section 4.6.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address fatigue of fuel transfer tube bellows, as required by 10 CFR 54.21(d).

4.6.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the fuel transfer tube bellows will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.6 Recirculation Sump Guard Piping Bellows Fatigue

4.6.6.1 Summary of Technical Information in the Application

LRA Section 4.6.6 describes the applicant’s TLAA for recirculation sump guard piping bellows fatigue. The LRA states that the guard pipe, which extends from the recirculation sump to the sump suction valve protection chamber inside the auxiliary building, is composed of a 28-in. diameter sleeve that includes two sets of expansion joints (bellows). The LRA also states that the bellows were analyzed for fatigue in accordance with Expansion Joint Manufacturers Association, 4th Edition, 1975, and substantiated per ASME Code Section III, Subparagraph NE-3365.2(e)(1), 1977 Edition through Summer of 1977 Addenda, which required 7,000 design cycles.

The LRA further states that:

> [t]hese bellows are affected by plant heatup and cooldown transients and other transients associated with accident conditions that would fill the containment recirculation sump, including OBE transients. These transients are listed in Section 4.3.1 and have 60-year projections that are less than the numbers of cycles analyzed for the bellows. Therefore, the design analysis of the bellows is acceptable for the period of extended operation. The BBS Fatigue Monitoring (B.3.1.1) Program monitors plant heatup and cooldown transients, as well as upset, emergency, and faulted conditions, including OBE and SSE events.

The applicant dispositioned the TLAA for the recirculation sump guard piping bellows in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.6.6.2 Staff Evaluation

The staff reviewed the applicant’s TLAA for the recirculation sump guard piping bellows and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function of the recirculation sump guard piping bellows will be adequately managed by the Fatigue Monitoring Program. The staff reviewed the applicant’s TLAA and disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which state that the applicant’s proposed AMP is reviewed to ensure that the effects of aging on the intended functions are adequately managed for the period of extended operation.

In its review, the staff noticed that LRA Section 4.6.6 states that the recirculation sump guard piping bellows are affected by plant heatup and cooldown transients and other transients associated with accident conditions that would fill the containment recirculation sump. However, it was not clear which of the transients listed in LRA Section 4.3.1 were considered to contribute towards the 7,000-cycle limit for which the bellows were designed; therefore, by letter dated April 24, 2014, the staff issued RAI 4.6.6-1, requesting that the applicant identify the applicable transients, including the cycle limit for each transient that was assumed in the design fatigue analysis for the recirculation sump guard piping bellows.

In its response dated May 23, 2014, the applicant revised LRA Sections 4.6.6 and A.4.6.6 to clarify the description of the configuration of the recirculation sump guard piping bellows. The RAI response clarified that the guard pipe actually includes three (3) sets of expansion joints (bellows), with one bellows sealing between the containment sump piping and the guard pipe located inside the containment structure. A second bellows seals between the guard pipe and the sump suction valve protection chamber inside the auxiliary building structure. The third set of bellows inside the auxiliary building which seal between the sump suction valve protection chamber and the recirculation sump effluent piping. The applicant stated that the cycle limit and the transients, which were assumed in the design fatigue analysis for the recirculation sump guard piping bellows, are different for the three sets of bellows, which the applicant described separately for the containment and auxiliary building as follows:

> <u>Containment Structure</u>
>
> The analysis for the recirculation sump guard piping bellows inside containment was performed in accordance with ASME Section III, Subparagraph NE-3365.2(e)(1), 1977 Edition through Summer of 1977 Addenda to determine the appropriate numbers of fatigue test cycles required to support the design requirement of 10 cycles. The applicable transient associated with the analysis performed for the recirculation sump guard piping bellows is only that associated with the LOCA event. The Current License Basis (CLB) LOCA event limit for this transient is one (1)…The Fatigue Monitoring Program currently includes tracking and monitoring of LOCA events….
>
> <u>Auxiliary Building Structure</u>
>
> …The 7,000 cycles are inputs to the analysis to qualify the bellows and are the cycle limits. The 7,000 cycles input to the analysis are similar to those evaluated in LRA Section 4.3.3, since the process pipe which is attached to the bellows is ASME Section III, Class 2. Both of these bellows assemblies in the auxiliary building do not perform a containment pressure boundary function. Similar to the disposition in LRA Section 4.3.3, for Class 2 fatigue analysis, the Fatigue Monitoring Program will monitor the transients provided in Tables 4.3.1-3 (Byron) and 4.3.1-6 (Braidwood), which are the transients that have the potential to impart differential movement intended for the bellows assemblies. OBE and SSE seismic events are other transients associated with the cyclic differential movement associated with seismic events. Monitoring and tracking of OBE and SSE seismic events is currently performed by the Fatigue Monitoring Program….

In its response, the applicant also revised LRA Section A.3.1.1 and B.3.1.1 to confirm monitoring of LOCA and SSE (seismic) events by the Fatigue Monitoring Program.

In its review of the response to RAI 4.6.6-1, the staff found the applicable transient associated with the analysis performed for the recirculation sump guard piping bellows in the containment structure is a LOCA event, and concluded that the applicant has revised the LRA to clearly indicate that the Fatigue Monitoring Program monitors the event. The staff concluded that the bellows in the auxiliary building structure addressed in this TLAA experience the same number of cycles as process pipe to which they are attached and have been dispositioned in SER Section 4.3.3. The staff also noticed that the transients provided in LRA Tables 4.3.1-3 (Byron) and 4.3.1-6 (Braidwood), which have the potential to impart differential movement intended for the bellows assemblies, show that total projected cycles at each site is fewer than the 7,000 allowed.

The staff finds the applicant's response acceptable because the applicant has clarified that the cycle limits and transients were different for the three sets of bellows, and the applicant has provided sufficient information for the staff to verify that the Fatigue Monitoring Program will adequately monitor and manage aging on the intended functions of the bellows. The staff's evaluation of the Fatigue Monitoring Program and acceptability of the enhancements is documented in SER Section 3.0.3.2.24. The staff's concern described in RAI 4.6.6-1 is resolved.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the recirculation sump guard piping bellows will be adequately managed for the period of extended operation.

Additionally, LRA Section 4.6.6 meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.3 because the Fatigue Monitoring Program will monitor transient cycles to ensure that, if a transient limit is approached, corrective action is taken prior to exceeding a transient limit.

4.6.6.3 UFSAR Supplement

LRA Section A.4.6.6 as amended by letter dated May 23, 2014, provides the UFSAR supplement summarizing the TLAA for recirculation sump guard piping bellows fatigue. The staff reviewed LRA Section A.4.6.6 consistent with the review procedures in SRP-LR Section 4.6.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the TLAA.

Based on its review of the amended UFSAR supplement, the staff finds LRA Section A.4.6.6 meets the acceptance criteria in SRP-LR Section 4.6.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address fatigue of recirculation sump guard piping bellows, as required by 10 CFR 54.21(d).

4.6.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the recirculation sump guard piping bellows will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 <u>Other Plant-Specific Time-Limited Aging Analyses</u>

4.7.1 Leak-Before-Break

Criterion 4, "Environmental and Dynamic Effects Design Bases," of 10 CFR Part 50, Appendix A, (General Design Criterion (GDC)-4) requires SSCs important to safety to be appropriately protected against dynamic effects associated with postulated pipe ruptures. However, protection against such dynamic effects is not required when analyses reviewed and approved by the staff demonstrate that the probability of rupture is extremely low under conditions consistent with the design basis for the piping. An approved LBB analysis permits the removal of protective hardware, such as pipe whip restraints and jet impingement barriers, the redesign of pipe connected components, their supports, and their internals, and other related changes, as described in SRP Section 3.6.3, "Leak-Before-Break Evaluation Procedures" (NUREG-0800).

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 describes the applicant's TLAA evaluations for the LBB analyses. The LRA identifies three TLAAs based on the existing LBB analyses: (1) a TLAA for the reactor coolant primary loop piping, (2) a TLAA for the safety injection accumulator piping and reactor coolant bypass piping, and (3) a TLAA for the safety injection accumulator piping cold leg nozzles.

The LRA states that the existing LBB analysis for the reactor coolant primary loop piping is documented in a report by Westinghouse, WCAP-14559, Revision 1, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Byron and Braidwood Units 1 and 2 Nuclear Power Plants," dated April 1996. The LRA also indicates that the staff accepted this analysis by letter dated October 25, 1996. The LRA states that the applicant updated this existing LBB analysis to account for the period of extended operation. Inputs for the updated analysis took into consideration the Mechanical Stress Improvement Process (MSIP®) applied to the reactor vessel inlet and outlet nozzles. In addition, the LRA states that the reactor coolant primary loop piping includes cast austenitic stainless steel (CASS) materials. Since CASS materials are subject to the effects of loss of fracture toughness due to thermal aging embrittlement over time, the applicant accounted for these effects in the updated LBB analysis by using the methodology in NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," dated May 1994. For the updated LBB analysis, the applicant postulated through-wall flaws at governing critical locations that would cause a leak rate 10 times the capability of the plant leakage detection systems. According to the LRA, the results of the updated LBB analysis demonstrate that such flaws have large margins against instability. Additionally, the LRA states that the applicant analyzed fatigue crack growth based on the design transients and cycles listed in LRA Section 4.3.1.

The LRA states that the existing LBB analysis for the safety injection accumulator piping and reactor coolant bypass piping is documented in a report by Sargent & Lundy, SL-4518, "Leak-Before-Break Evaluation for Stainless Steel Piping Byron and Braidwood Nuclear Power Stations Units 1 and 2," dated May 12, 1989. The LRA also indicates that the staff accepted this analysis by letter dated April 19, 1991. The LRA states that the applicant determined, from a review of the current calculation packages, that the loads used in the existing LBB analysis will still govern in the period of extended operation. The SL-4518 report also documents the existing LBB analysis for the safety injection accumulator piping cold leg nozzles. The LRA states that these nozzles are made of CASS materials, which are subject to the effects of loss of fracture toughness due to thermal aging embrittlement. The LRA states that the applicant updated the existing LBB analysis to account for these effects through the period of extended operation. For the updated LBB analysis, the LRA states that the applicant postulated a through-wall flaw size that would cause a leak rate 10 times the capability of the plant leakage detection systems. According to the LRA, the results of the updated LBB analysis demonstrate that such flaws have large margins against instability.

The applicant dispositioned the TLAA for the safety injection accumulator piping and reactor coolant bypass piping LBB analysis in accordance with 10 CFR 54.21(c)(1)(i) to demonstrate that the analysis remains valid for the period of extended operation. The applicant dispositioned the TLAAs for the reactor coolant primary loop piping LBB analysis and the safety injection accumulator piping cold leg nozzles LBB analysis in accordance with 10 CFR 54.21(c)(1)(ii) to demonstrate that the analyses have been projected to the end of the period of extended operation.

4.7.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA evaluations for the LBB analyses and the corresponding dispositions pursuant to 10 CFR 54.21(c)(1), consistent with the review procedures in SRP-LR Section 4.7.3.1. The staff discusses its evaluation of each TLAA in the sections that follow.

Reactor Coolant Primary Loop Piping. The staff reviewed the applicant's TLAA for the reactor coolant primary loop piping LBB analysis and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.7.3.1.2. These procedures state that the staff is to review the results of the applicant's revised analysis to verify that the evaluation period has been extended, such that the analysis is valid for the period of extended operation. The SRP-LR also states that the applicant may extend the period of evaluation by recalculating the analysis using a methodology that is in effect when the LRA is filed. In addition, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 3.6.3, "Leak-Before-Break Evaluation Procedures," dated March 2007, provides acceptance criteria and procedures for the staff's review of LBB analyses used to demonstrate compliance with GDC-4.

WCAP-14559, Revision 1 documents the existing LBB analysis for the reactor coolant primary loop piping. LRA Section 4.7.1 states that the applicant updated this analysis and the results demonstrate that there are large margins against the instability of postulated flaws. The staff reviewed LRA Section 4.7.1; however, it could not identify the methodology that the applicant used for the updated LBB analysis. Therefore, the staff could not determine whether the applicant updated the analysis using a methodology that is currently in effect, as recommended by SRP-LR Section 4.7.3.1.2. The staff also determined that the LRA did not contain a sufficient level of technical information for the staff to confirm that the updated LBB analysis demonstrates compliance with GDC-4 and the criteria in SRP Section 3.6.3. By letter dated April 24, 2014, the staff issued RAI 4.7.1-1, requesting that the applicant provide for staff review and approval the full update to the LBB analysis or the rationale for not providing it.

The applicant responded to RAI 4.7.1-1 by letter dated May 23, 2014. The response summarizes the applicant's update to the LBB analysis for the reactor coolant primary loop piping. The applicant stated that the primary difference between the existing LBB analysis and the updated LBB analysis is the method used to calculate the fracture toughness properties for the CASS materials. Specifically, the existing LBB analysis used fracture toughness properties after 40 years of aging, as calculated according to a report by Westinghouse, WCAP-10931, Revision 1, “Toughness Criteria for Thermally Aged Cast Stainless Steel,” dated July 1986, whereas the updated LBB analysis used fracture toughness properties after 60 years of aging, as calculated according to NUREG/CR-4513. The applicant stated that use of the new methodology changed the values of the elastic-plastic J-integral fracture mechanics inputs, but clarified that the results still satisfy the flaw stability criteria for the calculated fracture toughness and tearing modulus. In addition, the applicant stated that the existing LBB analysis was developed in accordance with the original (1987) version of SRP Section 3.6.3, whereas the updated LBB analysis was developed in accordance with the current (2007) version. The applicant explained that the primary difference between the two versions is that the current version includes a criterion on determining material susceptibility to primary water stress corrosion cracking (PWSCC), which is considered to be an active degradation mechanism for Alloy 82/182 welds in PWRs. The applicant stated that BBS have Alloy 82/182 welds in the reactor vessel hot and cold leg safe ends, but it has applied MSIP at these locations to mitigate the effects of PWSCC. The applicant’s response to RAI 4.7.1-1 also reports the results of the updated LBB analysis. The applicant stated that, after the application of MSIP for the Alloy 82/182 welds, the leakage flaw size is greater than 10 in. and the critical flaw sizes are all greater than 38 in. The applicant also stated that, per the existing LBB analysis, the two critical locations in the reactor coolant primary loop piping are at: (1) the hot leg elbow fitting into the steam generator, and (2) the cold leg discharge piping of the RCP. The applicant stated that the updated LBB analysis does not result in any change from these locations or any changes to the leakage flaw sizes and critical flaw sizes at these locations.

The staff reviewed the methodology for the applicant’s updated LBB analysis, as described in the response to RAI 4.7.1-1. The response indicates that the applicant prepared the updated LBB analysis using the existing methodology with new inputs to account for thermal aging embrittlement of the CASS materials and for the application of MSIP on the reactor vessel hot and cold leg safe ends. The applicant stated that it used NUREG/CR-4513 to determine the fracture toughness properties of the CASS materials at the end of the period of extended operation. Because NUREG/CR-4513 is the latest NRC-endorsed methodology specifically for this purpose, the staff finds it to be an acceptable methodology for generating the new inputs for the updated LBB analysis.

The staff also reviewed the applicant’s actions to address PWSCC because SRP Section 3.6.3 states that the LBB analysis should demonstrate that it is not a potential source of pipe rupture. The applicant’s response to RAI 4.7.1-1 states that it applied MSIP to the Alloy 82/182 welds in the reactor vessel hot and cold leg safe ends as a means to mitigate PWSCC. The staff noticed that RIS 2010-07, “Regulatory Requirements for Application of Weld Overlays and Other Mitigation Techniques in Piping Systems Approved for Leak-Before-Break,” dated June 8, 2010, states that MSIP is considered to be an adequate means to mitigate PWSCC and thus satisfy the related criterion in SRP Section 3.6.3. Based on the applicant’s statement that MSIP has been applied to the reactor vessel hot and cold leg safe ends, the staff finds that the applicant has taken adequate measures to mitigate PWSCC; therefore, the applicant may continue to apply the LBB analysis to the reactor coolant primary loop piping. RIS 2010-07 also indicates that MSIP may be applied without NRC authorization, since it does not affect any design or inspection requirements. Based on this information, the staff determined that the application of MSIP does not result in a change to the existing LBB methodology. In summary, the response to RAI 4.7.1-1 demonstrates that the applicant used its existing, NRC-approved methodology for the updated LBB analysis; therefore, the staff determined that the applicant does not need to provide the full update for review and approval. In addition, since the applicant used an existing methodology that is currently in effect, the staff determined that the applicant’s approach to updating the TLAA is consistent with the guidance in SRP-LR Section 4.7.3.1.2. The staff's concern described in RAI 4.7.1-1 is resolved.

The staff also reviewed the results of the applicant's updated LBB analysis. For dispositions made pursuant to 10 CFR 54.21(c)(1)(ii), SRP-LR Section 4.7.3.1.2 states that the applicant may recalculate the existing analysis using a 60-year period to show that the acceptance criteria continue to be satisfied for the period of extended operation. The response to RAI 4.7.1-1 states that the applicant's updated LBB analysis does not result in any changes to the leakage flaw sizes or critical flaw sizes at the critical locations, and these locations are unchanged from the existing LBB analysis. The staff reviewed and approved the results of the existing LBB analysis as documented by letter dated October 25, 1996. Since there are no changes to these results, the staff finds them to be acceptable for the reasons stated in the original approval letter. From the response to RAI 4.7.1-1, the safety margin on flaw size is 3.8 for the Alloy 82/182 welds to which MSIP was applied. The staff reviewed this result against the criteria in SRP Section 3.6.3, which state that the results of the deterministic fracture mechanics analysis should demonstrate that there is a safety margin of at least 2 between the critical flaw size and the leakage flaw size. The staff finds the result reported by the applicant acceptable because it is greater and thus more conservative than the safety margin recommended in SRP Section 3.6.3.

In addition, the LRA describes the results of the fatigue crack growth analysis. The staff confirmed that the transients used for this analysis are included in LRA Section 4.3 and that none of the transients are projected to exceed the number of cycles identified in the existing LBB analysis. On the basis of these projections, the staff determined that the applicant has adequately addressed fatigue crack growth for the updated LBB analysis.

The staff finds the applicant demonstrated pursuant to 10 CFR 54.21(c)(1)(ii), that the LBB analysis for the reactor coolant primary loop piping has been projected to the end of the period of extended operation. This demonstration also meets the acceptance criteria in SRP-LR Section 4.7.2.1.

Safety Injection Accumulator Piping and Reactor Coolant Bypass Piping. The staff reviewed the applicant's TLAA for the safety injection accumulator piping and reactor coolant bypass piping LBB analysis and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3.1.1. These procedures state that the applicant should show that the existing analysis bounds the period of extended operation, so that no reanalysis is necessary.

The SL-4518 report documents the existing LBB analysis for the safety injection accumulator piping and reactor coolant bypass piping. LRA Section 4.7.1 states that the loads used as inputs for this analysis will still govern in the period of extended operation; therefore, the LRA concludes that the existing LBB analysis remains valid. The staff reviewed LRA Section 4.7.1 and found that it does not identify any specific time-dependent loads or other parameters from the existing LBB analysis, nor does it demonstrate how these time-dependent parameters remain valid for the period of extended operation. By letter dated April 24, 2014, the staff issued RAI 4.7.1-2, requesting that the applicant identify all of the time-dependent parameters used in the existing LBB analysis and justify how each parameter will remain valid for the period of extended operation.

The applicant responded to RAI 4.7.1-2 by letter dated May 23, 2014. In its response, the applicant stated that the methodology used in the existing LBB analysis is consistent with the modified limit load approach described in SRP Section 3.6.3. The applicant also stated that the parameters for this analysis include the piping material properties, dimensions, and loadings. However, the applicant stated that none of these parameters are time-dependent; therefore, the applicant concluded that the existing LBB analysis does not meet the definition of a TLAA. The applicant also amended LRA Sections 4.7.1 and A.4.7.1 in its response, to remove all discussion of the existing LBB analysis for the safety injection accumulator piping and reactor coolant bypass piping as a TLAA.

The staff reviewed the applicant's response to RAI 4.7.1-2. Per the definition in 10 CFR 54.3, TLAAs are those calculations and analyses that, in part, involve time-limited assumptions defined by the current operating term. The staff reviewed the existing LBB analysis for the safety injection accumulator piping and reactor coolant bypass piping and confirmed that it uses a limit load analysis as indicated in the applicant's RAI response. In a limit load analysis, the stability of a postulated flaw is assessed in terms of the applied loads, and there is no assessment of flaw growth over time. In addition, the safety injection accumulator piping and reactor coolant bypass piping are not made of CASS, so the piping is not susceptible to the time-based effects of loss of fracture toughness due to thermal aging. For these reasons, the staff determined that the existing LBB analysis does not involve any time-limited assumptions defined by the current operating term. Therefore, the staff determined that the analysis does not meet the definition of a TLAA in 10 CFR 54.3. Accordingly, the existing LBB analysis for the safety injection accumulator piping and reactor coolant bypass piping does not need to be evaluated against the requirements of 10 CFR 54.21(c)(1). The staff's concern described in RAI 4.7.1-2 is resolved.

Safety Injection Accumulator Piping Cold Leg Nozzles. The staff reviewed the applicant's TLAA for the safety injection accumulator piping cold leg nozzles LBB analysis and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.7.3.1.2. These procedures state that the staff is to review the results of the applicant's revised analysis to verify that the evaluation period has been extended, such that the analysis is valid for the period of extended operation. The SRP-LR also states that the applicant may extend the period of evaluation by recalculating the analysis using a methodology that is in effect when the LRA is filed. In addition, SRP Section 3.6.3 provides acceptance criteria and procedures for the staff's review of LBB analyses used to demonstrate compliance with GDC-4.

The SL-4518 report documents the existing LBB analysis for the safety injection accumulator piping cold leg nozzles. The report indicates that these nozzles are made of CASS, which is susceptible to the effects of loss of fracture toughness due to thermal aging embrittlement. LRA Section 4.7.1 states that the applicant determined new fracture toughness properties for the CASS materials based on their aging through the period of extended operation, and then used the new material properties to generate the updated LBB analysis. The staff reviewed LRA Section 4.7.1; however, it could not identify the methodology that the applicant used for the updated LBB analysis. Therefore, the staff could not determine whether the applicant updated the analysis using a methodology that is currently in effect, as recommended by SRP-LR Section 4.7.3.1.2. The staff also determined that the LRA did not contain a sufficient level of technical detail for the staff to confirm that the updated LBB analysis complies with the requirements of GDC-4 and the criteria in SRP Section 3.6.3. By letter dated April 24, 2014, the staff issued RAI 4.7.1-3, requesting that the applicant provide for staff review and approval the full update to the LBB analysis or the rationale for not providing it. The staff also requested that the applicant identify and provide justification for the methodology used to determine the fracture toughness properties for the CASS materials.

The applicant responded to RAI 4.7.1-3 by letter dated May 23, 2014. The response summarizes the update to LBB analysis for the safety injection accumulator piping cold leg nozzles. The applicant stated that the existing LBB analysis was developed in accordance with the original (1987) version of SRP Section 3.6.3, whereas the updated LBB analysis was developed in accordance with the current (2007) version. The applicant stated that the primary difference between the two versions is that the current version includes a criterion on determining material susceptibility to PWSCC, which is considered to be an active degradation mechanism for Alloy 82/182 welds in PWRs. However, the applicant stated that the safety injection accumulator piping cold leg nozzles are not made of this material, so the criterion is not applicable. The applicant also stated that the primary difference between the existing LBB analysis and the updated LBB analysis is the calculation of the fracture toughness properties for the CASS nozzles. The applicant explained that the existing LBB analysis used fracture toughness properties based on generic material data in the staff's Piping Fracture Mechanics Data Base. However, for the updated LBB analysis, the applicant determined the fracture toughness properties using the plant-specific CMTRs and the methodology in NUREG/CR-4513. As to the results of the updated LBB analysis, the applicant stated that the ratio of the critical flaw size to the leakage flaw size is 3.3. In addition, the applicant stated that the updated fracture toughness properties demonstrate significant margin against the instability of flaws.

The staff reviewed the methodology for the applicant's updated LBB analysis, as described in the response to RAI 4.7.1-3. This response indicates that the applicant prepared the updated LBB analysis using the existing methodology with new inputs to account for thermal aging embrittlement of the CASS safety injection accumulator piping cold leg nozzles. The applicant stated that it used NUREG/CR-4513 to determine the fracture toughness properties of the CASS materials at the end of the period of extended operation. Because NUREG/CR-4513 is the latest NRC-endorsed methodology specifically for this purpose, the staff finds it to be an acceptable methodology for generating the new inputs for the updated LBB analysis. In addition, the staff determined that the safety injection accumulator piping cold leg nozzles are not susceptible to PWSCC because they are not made of Alloy 82/182. Therefore, the related criterion from SRP Section 3.6.3 is satisfied. In summary, the response to RAI 4.7.1-3 demonstrates that the applicant used its existing, NRC-approved methodology for the updated LBB analysis; therefore, the staff determined that the applicant does not need to provide the full update for review and approval. In addition, since the applicant used an existing methodology that is currently in effect, the staff determined that the applicant's approach to updating the TLAA is consistent with the guidance in SRP-LR Section 4.7.3.1.2. The staff's concern described in RAI 4.7.1-3 is resolved.

The staff also reviewed the results of the applicant's updated LBB analysis. For dispositions made pursuant to 10 CFR 54.21(c)(1)(ii), SRP-LR Section 4.7.3.1.2 states that the applicant may recalculate the existing analysis using a 60-year period to show that the acceptance criteria continue to be satisfied for the period of extended operation. The response to RAI 4.7.1-3 reports a safety margin of 3.3 based on the updated LBB analysis. The staff reviewed this result against the criteria in SRP Section 3.6.3, which state that the results of the deterministic fracture mechanics analysis should demonstrate that there is a safety margin of at least 2 between the critical flaw size and the leakage flaw size. The staff finds the result reported by the applicant acceptable because it is greater and thus more conservative than the safety margin recommended in SRP Section 3.6.3.

The staff finds the applicant demonstrated pursuant to 10 CFR 54.21(c)(1)(ii), that the LBB analysis for the safety injection accumulator piping cold leg nozzles has been projected to the end of the period of extended operation. This demonstration also meets the acceptance criteria in SRP-LR Section 4.7.2.1.

4.7.1.3 UFSAR Supplement

LRA Section A.4.7.1 provides the UFSAR supplement summarizing the TLAA evaluations for the LBB analyses. The staff reviewed LRA Section A.4.7.1 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the applicant is to provide a summary description for its evaluation of each TLAA. The SRP-LR also states that the summary description should contain information on the disposition of the TLAA for the period of extended operation and be appropriate such that later changes can be controlled by 10 CFR 50.59. By letter dated May 23, 2014, the applicant amended LRA Section A.4.7.1 to reflect its response to RAI 4.7.1-2. Accordingly, the applicant deleted the portion of the summary description on the analysis for the safety injection accumulator piping and reactor coolant bypass piping because this analysis is not a TLAA. Based on its review of the UFSAR supplement, as amended by letter dated May 23, 2014, the staff finds that LRA Section A.4.7.1 meets the acceptance criteria in SRP-LR Section 4.7.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the updates to the LBB analyses for the reactor coolant primary loop piping and the safety injection accumulator piping cold leg nozzles, as required by 10 CFR 54.21(d).

4.7.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided acceptable demonstrations, pursuant to 10 CFR 54.21(c)(1)(ii), that the LBB analyses for the reactor coolant primary loop piping and the safety injection accumulator piping cold leg nozzles 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 evaluations, as required by 10 CFR 54.21(d).

4.7.2 Crane Load Cycle Limits

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 describes the applicant's TLAAs for load cycle limits of cranes designed in accordance with the Crane Manufacturers Association of America Specification 70 (CMAA-70). The LRA states that, based upon frequency of operation and expected size of load relative to their maximum load capacity, these cranes are designated a given service classification with an expected maximum number of design cycles over their life, which correlates to a number of cycles on structural members. The service class is used to define the allowable stress range limits for structural members and fasteners, considering the cyclic operation over the life of the crane. Therefore, since the maximum number of design load cycles over the 40-year life of the crane provides the basis for acceptability of the design for cyclic operation, the load cycles experienced over the period of extended operation need to be evaluated. LRA Table 4.7.2-1 summarizes the evaluation of cyclic operation for each crane.

The applicant dispositioned the TLAAs for the containment polar crane, fuel handling building crane, manipulator crane, SFP bridge crane, and turbine building crane in accordance with 10 CFR 54.21(c)(1)(i) to demonstrate that the analyses remain valid for the period of extended operation.

4.7.2.2 Staff Evaluation

The staff reviewed the applicant's TLAAs for the containment polar crane, fuel handling building crane, manipulator crane, SFP bridge crane, and turbine building crane and the corresponding disposition that the projected number of load cycles is less than the design load cycles used in the cyclic analyses, consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which state that the existing analyses should be shown to be bounding even during the period of extended operation. The SRP-LR also states that the applicant should describe the TLAA with respect to the objectives of the analysis, assumptions used in the analysis, conditions, acceptance criteria, relevant aging effects, and intended functions. The applicant should show that conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation, and acceptance criteria are maintained to provide reasonable assurance that the intended functions are maintained for the period of extended operation.

Containment Polar Crane. In its review of the cyclic analysis for the containment polar cranes, the staff confirmed that UFSAR Section 9.1.4.2.2 and Table 9.1-7, "Crane Design," states that the cranes were designed for CMAA-70, 1975 Revision, Class A service (100,000 load cycles), based on a design load of 230 tons on the main hook, and 40 tons on the auxiliary hook. They were also designed to withstand the containment pressure test, and OBE and SSE stresses. The applicant estimated 44 load cycles of 5 tons or greater, for each crane per refueling outage, over the 60-year plant life, and considered an additional 100 load cycles for crane use during original construction and Unit 1 steam generator replacement at both BBS. The staff noticed that the applicant assumed the load cycles performed by all four containment polar cranes were similar, with the steam generator replacement being the only significant difference, and therefore, has considered the analysis for BBS, Unit 1, containment polar cranes to be bounding since steam generators have not been replaced at either Byron or Braidwood, Unit 2.

The estimated number of load cycles for each containment polar crane over the course of the 60-year life of the plant, based on 40 refueling outages, is 1,860, or approximately 1,900 load cycles. This is less than the number of load cycles (100,000) considered when determining the allowable stress for which they were designed and, therefore, is acceptable.

Fuel Handling Building Crane. In its review of the cyclic analysis for the fuel handling building crane, the staff reviewed LRA Section 4.7.2 and UFSAR Section 9.1.4.2.2 and Table 9.1-7, "Crane Design," and noticed that the single fuel handling crane at BBS was designed for CMAA-70, 1975 Revision, Class A Service (100,000 load cycles). The staff also noticed that the fuel handling building overhead crane is equipped with a 125-ton main hoist and 15-ton auxiliary hoist, and is used for lifts associated with RCP motor replacement and refurbishment, dry cask storage campaigns, and outage equipment staging. The applicant estimated 1,200 load cycles for activities other than dry cask storage campaigns and that a normal dry cask storage campaign involves an equivalent of six casks every 18 months and 25 load cycles per cask, thereby resulting in a projected 6,000 loads over the course of 60 years. Considering that BBS began dry cask storage campaigns in 2010 and 2011, respectively, the staff agrees that the applicant's estimated number of load cycles is conservative.

The estimated number of load cycles for the fuel handling building crane over the course of the 60-year life of the plant, based on the normal dry cask storage schedule described above and activities other than the dry cask storage campaigns, is 7,200 load cycles. This is less than the number of load cycles (100,000) considered when determining the allowable stress for which it was designed and, therefore, is acceptable.

Manipulator Crane. In its review of the cyclic analysis for the manipulator crane, the staff reviewed LRA Section 4.7.2, UFSAR Section 9.1.4.2.2, and Table 9.1-7, "Crane Design," and UFSAR Section 9.1.4.2.2, "Component Description," which states that the crane, referred to as either manipulator crane or refueling machine, was designed in accordance with CMAA-70, for Class C service (500,000 load cycles). CMAA Table 3.3.3.1.3-1 indicates that the allowable stress range for a crane designed for Class C service is between 100,000 and 500,000 load cycles. The applicant estimated 400 load cycles each refueling outage, which includes offload and reload of 193 assemblies, two pull tests at greater than 150 percent of the weight of the assembly, and two source assembly moves.

The estimated number of load cycles for each manipulator crane (refueling machine) over the course of the 60-year life of the plant, based on 40 refueling outages, is approximately 16,000 load cycles. This is less than the number of load cycles (100,000–500,000) considered when determining the allowable stress for which they were designed and, therefore, is acceptable.

Spent Fuel Pool Bridge Crane. In its review of the cyclic analysis for the SFP bridge crane, the staff reviewed LRA Section 4.7.2, UFSAR Section 9.1.4.2.2 and Table 9.1-7, "Crane Design," and UFSAR Section 9.1.4.2.2, "Component Description," and noticed that the SFP bridge crane was designed in accordance with CMAA-70 for Class A service (100,000 load cycles). Because the SFP is common between units at BBS, there is a single SFP bridge crane at each station that handles fuel moves associated with both units. For the single SFP bridge crane at each station, the applicant estimated a total of 41,500 load cycles, about 1032, every 18 months to support an assumed 40 operating cycles for each unit, 9,000 load cycles associated with dry cask storage campaigns, and 26,400 load cycles associated with miscellaneous activities, which include SFP rerack projects, fuel assembly moves for checker-boarding, gamma heating, and insert moves, and B.5.b moves, as described in LRA Section 4.7.2.

The total estimated number of load cycles for the SFP bridge crane over the 60-year life of the plant, based on 40 refueling outages for each unit, is approximately 76,900 load cycles. This is less than the number of load cycles (100,000) considered when determining the allowable stress for which it was designed and, therefore, is acceptable.

Turbine Building Crane. In its review of the cyclic analysis for the turbine building crane, the staff reviewed LRA Section 4.7.2 and UFSAR Section 9.1.4.2.2 and Table 9.1-7, "Crane Design," and noticed that the turbine building crane was designed in accordance with CMAA-70, 1975 Revision, for Class A service (100,000 load cycles) and includes a 150 ton capacity main hoist and 25 ton capacity auxiliary hoist. The staff also noticed that there is one crane for each unit at BBS, and that the applicant assumed the load cycles performed by each crane are similar. The applicant estimated 4,800 cycles over the 60-year life based on review of crane operation, and has added an additional 200 initial load cycles for use during construction and 100 load cycles for future equipment and system upgrades, for a total of 5,100 load cycles.

The estimated number of load cycles for the turbine building crane over the course of the 60-year life of the plant, is 5,100 load cycles. This is less than the number of load cycles (100,000) considered when determining the allowable stress for which it was designed and, therefore, is acceptable.

In summary and based on its review, the staff finds the applicant demonstrated pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the containment polar crane, fuel handling building crane, manipulator crane, SFP bridge crane, and turbine building crane remain valid for the period of extended operation.

Additionally, LRA Section 4.7.2 meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant demonstrated that the projected load cycles over 60 years of operation will not exceed the design load cycles used in the cyclic analyses.

4.7.2.3 UFSAR Supplement

LRA Section A.4.7.2 provides the UFSAR supplement summarizing the crane load cycle limits. The staff reviewed LRA Section A.4.7.2 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the applicant should provide information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA. SRP-LR Section 4.7.3.2 also states that each summary description should be reviewed to verify that it is appropriate, such that later changes can be controlled by 10 CFR 50.59 and that the description should contain information that the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds LRA Section A.4.7.2 meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address crane load cycle limits, as required by 10 CFR 54.21(d).

4.7.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the containment polar crane, fuel handling building crane, manipulator crane, SFP bridge crane, and turbine building crane remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Mechanical Environmental Qualification

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 describes the applicant's TLAA for its mechanical environmental qualification (MEQ) program. The applicant stated that qualified lives and replacement intervals are established for safety-related mechanical components located in harsh environments based on aging concerns. Replacement intervals are identified either on the basis of aging performed during an IEEE 323-1974 (Institute of Electrical and Electronics Engineers) qualification test program or on the basis of published material aging data. The results of qualification tests or other published material aging data are documented in individual mechanical component EQ binders. Since some of the variables analyzed are based upon 40-year assumptions, these qualifications have been identified as TLAAs that require evaluation for the period of extended operation. The individual mechanical component's EQ documents will be revised to address the 60-year component service requirements in accordance with the BBS Environmental Qualification Program (EQP).

The applicant dispositioned the TLAA for MEQ in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of aging on the intended functions of mechanical equipment located in harsh environments will be adequately managed by the Byron and Braidwood EQP for the period of extended operation.

4.7.3.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the safety-related mechanical components located in harsh environments and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that:

(a) The applicant identifies the SCs associated with the TLAA.

(b) The TLAA is described with respect to the objectives of the analysis, conditions, assumptions used, acceptance criteria, relevant aging effects, and intended function(s).

(c) In cases where a mitigation or inspection program is proposed, the reviewer uses the guidance provided in Branch Technical Position RLSB-1 of the SRP-LR to ensure that the effects of aging on the structure and component intended function(s) are adequately managed for the period of extended operation.

The staff's evaluation of the above criteria is as follows:

(a) The TLAA included a generic description (i.e., safety-related mechanical components located in harsh environments) to define the scope of components associated with the TLAA in lieu of a list of SCs associated with the TLAA. During the AMP audit, the staff reviewed all of the mechanical component environmental qualification binders included within the scope of the Byron and Braidwood EQP and determined that the components are consistent with the generic description of the TLAA.

(b) In LRA Section 4.7.3, the applicant stated that, "[t]he design basis conditions during the period of extended operation will remain the same as those in the current license period." The staff noticed that UFSAR Table 3.11-2, "Plant Environmental Conditions," contains a listing of the environmental parameters associated with temperature, relative humidity, pressure, and integrated dose for normal, abnormal, and accident conditions. The applicant also stated that qualified lives are based IEEE 323-1974 qualification tests or published material aging data.

    During the AMP audit, the staff reviewed all of the mechanical component environmental qualification binders and confirmed that each component or subcomponent has a specific replacement frequency (i.e., qualified life). The staff confirmed that approximately two-thirds of the components within the scope of this TLAA have been analyzed for the impact of a 60-year life. The staff noticed that replacement frequencies vary, resulting in qualified lives ranging from less than 40 years to much more than 60 years. The staff also found that the plant-specific program requires that a component or subcomponent be replaced when it has reached the end of its qualified life. During the audit, the staff confirmed that the Byron and Braidwood EQP plant-specific procedure states that changes to the qualified lives of components are evaluated by the station environmental qualification engineer. Therefore the staff concludes that the remaining one-third of components within the program will either be replaced at the end of their qualified lives or the applicant will perform evaluations to determine if the qualified life can be extended.

In addition, during the AMP audit, the staff reviewed several documents that supported the qualified lives for components within the scope of the TLAA. The staff noticed that replacement frequencies are defined for all the components in the program and frequencies are based on IEEE 323-1974 qualification tests or on the basis of published material aging data (i.e., standard material property data sources).

(c) The applicant has not proposed a mitigation or inspection program, but instead will control the replacement of the components or component subparts using its Byron and Braidwood EQP. The use of the individual mechanical component documents is cited in LRA Section A.4.7.3. However, during its review of the mechanical component environmental qualification binders, the staff noticed that several of the components have condition monitoring surveillance requirements, such as (a) the external parts of the containment spray pumps and main steam power operated relief valves are required to be inspected for aging related degradation during each fuel load outage and be replaced immediately if such degradation is detected, (b) the main feed isolation valves should be inspected for packing and gasket leaks, (c) the main steam power-operated relief valve hydraulic operator should be checked for oil leakage, and (d) the main feed isolation valve hydraulic operators have inspection and oil sample requirements. It was not clear to the staff whether the surveillance requirements have been incorporated into AMPs. By letter dated February 18, 2014, the staff issued RAI 4.7.3-1 requesting that the applicant state the basis for why the condition monitoring activities described in the EQ binders are not required to be performed in order to establish reasonable assurance that the affected components and subcomponents will meet their qualified life, or state how the condition monitoring requirements will be incorporated into AMP.

In its response dated March 4, 2014, the applicant stated that the condition monitoring requirements that are required to establish reasonable assurance that the affected mechanical components and subcomponents will meet their qualified lives will be incorporated into the Environmental Qualification (EQ) of Electric Components program.

The applicant revised LRA Sections 2.5.2.1, 2.5.2.2, 2.5.2.4 to identify MEQ components as a commodity group. The applicant also added MEQ components to LRA Table 3.6.2-1, which states that these components are: constructed from various organic elastomers, exposed to an adverse localized environment, and subject to various aging effects which will be managed by the Environmental Qualification (EQ) of Electric Components program. The applicant revised LRA Sections A.1.3, A.3.1.3, B.1.6, and B.3.1.3, as well as Commitment No. 45, to include the MEQ components in the scope of the Environmental Qualification (EQ) of Electric Components program. The applicant identified an enhancement to the program to include the MEQ components.

The staff's evaluation of the Environmental Qualification (EQ) of Electric Components program and the above enhancement is documented in SER Section 3.0.3.1.20. The staff finds the applicant's response acceptable because the conditioning monitoring activities required by the mechanical component environmental qualification binders will be adequately managed by the Environmental Qualification (EQ) of Electric Components program. The program includes maintenance, surveillance, and replacement activities capable of providing reasonable assurance that the MEQ components will meet their CLB function(s) during the period of extended operation. The staff's concern described in RAI 4.7.3-1 is resolved.

The staff finds that the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of safety-related mechanical components located in harsh environments will be adequately managed for the period of extended operation.

Additionally, the TLAA meets the acceptance criteria in SRP-LR Section 4.7.3.1.3 because: (a) the scope of components associated with this TLAA are controlled by a plant-specific procedure; (b) affected components are identified in individual mechanical component EQ documents; (c) appropriate conditions and assumptions for the evaluation of components are included in the UFSAR; (d) the use IEEE 323-1974 qualification tests or published material aging data are standard industry methods for establishing qualified lives of mechanical equipment located in harsh environments; (e) the UFSAR supplement requires the use of mechanical component EQ documents, which specify the replacement frequency; (f) plant-specific procedures ensure that the appropriate plant staff conducts the review of changes to the mechanical component documents; and (g) conditioning monitoring activities for the MEQ components that are required to establish reasonable assurance that the affected MEQ components will meet their qualified lives will be managed by the maintenance, surveillance, and replacement activities in the Environmental Qualification (EQ) of Electric Components program.

4.7.3.3 UFSAR Supplement

LRA Section A.4.7.3 provides the UFSAR supplement summarizing the safety-related mechanical components located in harsh environments TLAA. The staff reviewed LRA Section A.4.7.3 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the summary description is reviewed to verify that it is appropriate, such that later changes can be controlled by 10 CFR 50.59 and it contains information that the TLAA has been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.3.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the replacement of safety-related mechanical components located in harsh environments, as required by 10 CFR 54.21(d).

4.7.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of safety-related mechanical components located in harsh environments will be adequately managed by the BBS EQ of Electric Components Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.4 Residual Heat Removal Heat Exchangers Tube Side Inlet and Outlet Nozzles Fracture Mechanics Analysis

4.7.4.1 Summary of Technical Information in the Application

LRA Section 4.7.4 describes the applicant's TLAA for flaws detected in RHR heat exchanger tube side inlet and outlet nozzles made of SS. During ultrasonic testing (UT) examinations in 1991, indications were found in the Braidwood Unit 2 RHR heat exchanger nozzles. Some of the indications exceeded the acceptance standards of ASME Section XI, IWB-3500 (1983 Edition through Summer 1983 Addenda) and were subjected to further evaluation in accordance with ASME Section XI, IWB-3600. Even though this component is an ASME

Class 2 component, a Class 1 fracture-mechanics-based flaw growth analysis was performed and this flaw growth analysis was used to disposition the indications that did not meet the IWB-3500 acceptance standards. This analysis for the Braidwood Unit 2 flaws was submitted to the staff for review and the staff reviewed and approved the analysis.

Subsequently, UT examinations were performed on all the BBS RHR heat exchanger nozzles and any additional indications exceeding the IWB-3500 acceptance standards were dispositioned with the analytical results. The following documents, as submitted to the staff on August 25, 1992, present the methodology for dispositioning the flaws found at BBS: (1) WCAP-13454, "Fracture Mechanics Evaluation, Byron and Braidwood Units 1 and 2, Residual Heat Exchanger Tube Side Inlet and Outlet Nozzles," August 1992 (Proprietary), and (2) WCAP-13455, "Fracture Mechanics Evaluation, Byron and Braidwood Units 1 and 2, Residual Heat Exchanger Tube Side Inlet and Outlet Nozzles," August 1992 (Non-proprietary, ADAMS Accession No. 9208280207). This analysis uses the startup and shutdowns of the RHR system coincident with the number of plant heatup and cooldowns based on the current licensed operation period as inputs.

The applicant dispositioned the TLAA for the flaws of RHR heat exchanger nozzles in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue flaw growth on the intended functions will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The Fatigue Monitoring program will monitor transient cycles to ensure the transient inputs used in the flaw growth analysis will not be exceeded during the period of extended operation.

4.7.4.2 Staff Evaluation

The staff reviewed the applicant's fracture-mechanics-based flaw growth analysis for the RHR heat exchanger nozzles made of SS, consistent with the review procedures in SRP-LR Section 4.7.3.1.3. The review procedures state that the applicant proposes to manage the aging effects associated with the TLAA by an AMP in the same manner as described in the IPA in 10 CFR 54.21(a)(3). The review procedures also state that the reviewer reviews the applicant's AMP to verify that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation. The review procedures further state that the TLAA is described with respect to the objectives of the analysis, conditions, assumptions used, acceptance criteria, relevant aging effects, and intended function(s).

During its review of LRA Section 4.7.4 and related information, the staff noticed a relief request by the applicant, which indicated that an ASME Section XI repair by excavation was completed on the unacceptable flaws of the Braidwood Unit 2 RHR heat exchanger nozzle-to-vessel welds ("Relief from Inservice Inspection Requirements for Residual Heat Removal Heat Exchanger Nozzle-to-Vessel Welds," December 12, 1995, ADAMS Accession No. 951219036). This reference regarding the relief request stated that the Braidwood, Unit 2 flaws were fabrication flaws, slag, incomplete fusion and excess porosity. The staff noticed that the above reference did not identify any other unacceptable flaws of the BBS RHR heat exchanger nozzles.

Therefore, it was unclear to the staff whether there are flaws currently in these nozzles which exceed the acceptance standards of ASME Code Section XI IWB-3500. It was also unclear to the staff whether the applicant's fracture mechanics analysis is relied upon to support the continued service of the heat exchangers, or the applicant's relief request for an alternative to the ASME Code ISI method.

By letter dated February 26, 2014, the staff issued RAI 4.7.4-1. In Part 1 of RAI 4.7.4-1, the staff requested that the applicant clarify whether there are flaws currently in the nozzles that exceed the acceptance standards of ASME Code Section XI IWB-3500. The staff also requested that the applicant clarify whether its flaw growth analysis is relied on to support: (a) continued service of the heat exchanger nozzles with existing flaws, or (b) the applicant's relief request for an alternative to the ASME Code ISI method for these nozzles (e.g., performing VT-2 visual examination in place of UT examination).

In Part 2 of the RAI, the staff stated that relief requests for inservice inspections are only valid for the current ISI ten-year interval and are required to be resubmitted for each interval for the period of extended operation, if desired. The staff also requested that, if the flaw growth analysis is relied upon to support the use of an alternate inspection method under a relief request process, the applicant clarify why the relief request process is not identified as part of the 10 CFR 54.21(c)(1)(iii) aging management basis in conjunction with the applicant's analysis.

In Part 3 of the RAI, the staff requested that the applicant provide the following information for the applicant's analysis: (a) current flaw sizes (i.e., length and depth), orientations (i.e., circumferential and axial) and locations based on the most recent inspection results in comparison with nozzle dimensions, and (b) projected flaw sizes at the end of the period of extended operation. The staff also requested that, as an alternative to (a) and (b), if a bounding-case analysis is applicable to each nozzle, the applicant provide the maximum current flaw size and maximum projected flaw size with the associated orientation and location which bound the other flaws for each nozzle. The staff further requested that the applicant describe the acceptance criteria for the flaws and when the most recent volumetric examination was performed on each nozzle. In addition, the staff requested that, as part of this response, the applicant provide the relevant transient names and projected numbers of transient cycles for the applicant's analysis.

By letter dated March 28, 2014, the applicant responded to RAI 4.7.4-1. In its response to Part 1 of RAI 4.7.4-1, the applicant stated that BBS Unit 1 and 2 RHR heat exchanger tube side inlet and outlet nozzle welds currently contain flaws that exceed the acceptance standards of ASME Code, Section XI, IWB-3500, 1983 Edition through Summer 1983 Addenda. The applicant also stated that these flaws, which were found between 1991 and 1994, were determined to be fabrication flaws. The applicant further stated that, even though these heat exchangers are ASME Class 2 components, a Class 1 fracture mechanics analysis, which met the requirements of ASME Code, Section XI, IWB-3600, was performed on these flaws.

In the response to Part 1, the applicant also stated that the flaws, which satisfied ASME Section XI, IWB-3640 requirements, were determined to be acceptable and remain in service today. The applicant stated that only flaws on the Braidwood Unit 2 "B" heat exchanger outlet nozzle did not satisfy ASME Code, Section XI, IWB-3640 requirements and were repaired in 1994. In addition, the applicant stated that the fracture mechanics analysis supporting the flaw evaluations were submitted to the staff, and the staff reviewed and approved the analysis in a letter dated February 3, 1995, "Residual Heat Exchanger Nozzle Welds, Byron Station, Unit 1 and 2, and Braidwood Station, Units 1 and 2 (TAC Numbers M90894, M90895, M91408, and M90840)," ADAMS Accession Number 9502130037.

In the response to Part 2, the applicant stated that the fracture mechanics analysis of the flaws is relied on to support continued service of the heat exchanger nozzles. The applicant also indicated that ASME Code Case N-706 was endorsed as "acceptable" (not "conditional") by the staff in 2007 as documented in RG 1.147, Revision 15, "Inservice Inspection Code Case

Acceptability ASME Section XI, Division 1." The applicant further stated that as such, the submittal for a relief request to use this code case is not required, and the relief request process is not applicable. The staff concluded that ASME Code Case N-706 was subsequently revised to Code Case N-706-1, which was approved in RG 1.147, Revision 16.

In the response to Part 2, the applicant also stated that ASME Code Case N-706-1 provides relief from the requirement to perform a UT examination of the welds on PWR SS regenerative and residual heat exchangers. The applicant stated that the code case allows VT-2 inspections of the welds in lieu of the UT examination, provided the welds have been volumetrically examined at least once. In addition, the applicant stated that since the BBS RHR heat exchanger nozzle welds have all been volumetrically examined with UT and been dispositioned in accordance with the flaw growth analysis, the use of the code case to perform VT-2 examinations of the welds instead of UT examinations is permissible. The applicant stated that, as discussed above, the use of ASME Code Case N-706-1 relies upon the fracture mechanics analysis.

In the response to Part 3, the applicant stated that the flaw growth analysis provides a bounding-case analysis which is applicable to each RHR heat exchanger tube side inlet and outlet nozzle. The applicant also indicated that Flaw Number 3 on the Braidwood Unit 2 "B" RHR heat exchanger inlet nozzle bounds all flaws that were dispositioned as acceptable for continued service. The applicant further stated that this flaw has an "as found" crack depth of 0.300 in. in a portion of the nozzle with a wall thickness of 0.526 in. In addition, the applicant indicated that applying the fatigue flaw depth growth of 0.001 in., based on an additional 200 cycles, results in a projected flaw depth of 0.301 in. at the end of the period of extended operation. In addition, the applicant stated that the fraction of the projected flaw depth with respect to the nozzle wall thickness would be 57.2 percent, which meets the acceptance criterion. The applicant stated that the flaw growth analysis concludes that for each inlet and outlet nozzle, the appropriate acceptance criterion, in accordance with ASME Code, Section XI, IWB-3460, is a maximum allowed flaw depth of 60 percent of the nozzle wall thickness.

In the response to Part 3, the applicant also stated that the most recent volumetric examinations performed on each nozzle are as follows:

- Braidwood Unit 1, 1RH02AA and 1RH02AB inlet and outlet nozzles, 1992
- Braidwood Unit 2, 2RH02AA and 2RH02AB inlet and outlet nozzles, 1994
- Byron Unit 1, 1RH02AA and 1RH02AB inlet and outlet nozzles, 1993
- Byron Unit 2, 2RH02AA and 2RH02AB inlet and outlet nozzles, 1992

The applicant further stated that the flaw evaluation methodology in the analysis includes loading conditions for thermal expansion, internal pressure, deadweight, and operating basis and safe shutdown earthquakes for the RHR heat exchanger inlet and outlet nozzles. The applicant stated that the flaw growth analysis considers fatigue due to applied stresses during transients and residual stresses, and is also based on ASME Code, Section XI, Appendix C (1989 Addenda). In addition, the applicant stated that the RHR heat exchangers are only used when the RCS is cooled down to cold shutdown and refueling, as the RHR system is placed into service, and later during RCS heatup until the RHR system is taken out of service.

The applicant indicated that the flaw growth analysis conservatively assumed 200 cycles corresponding to 200 plant heatups and plant cooldowns (i.e., transients 1 and 2 in LRA Tables 4.3.1-1 and 4.3.1-4 for Byron and Braidwood, respectively) over the 60-year period of operation. The applicant also stated that, based on the assumed cycles, the analysis results in a fatigue flaw depth growth of less than 0.001 in. such that the projected flaw depth after 200 cycles is calculated by adding 0.001 in. to the "as-found" flaw depth. The applicant further stated that the maximum number of plant heatups and plant cooldowns projected for 60 years is 117 on Byron Unit 1, which bounds all four units.

The staff noticed that the applicant confirmed that RHR heat exchanger tube side nozzles currently contain flaws that exceed the acceptance standards of ASME Code, Section XI, IWB-3500. The staff also noticed that the applicant confirmed that the bounding-case analysis (Braidwood Unit 2, "B" RHR heat exchanger inlet nozzle) indicates that the maximum fatigue flaw growth of 0.001 in. results in the bounding-case flaw depth of 0.301 in. as projected at the end of the period of extended operation. In addition, the staff noticed that the applicant confirmed that the projected flaw depth projected is acceptable against the acceptance criteria of ASME Code Section XI, IWB-3640.

In its review, the staff noticed that the applicant also indicated that the most recent volumetric examinations for the RHR heat exchanger nozzles were those performed in 1994 on Braidwood Unit 2 RHR heat exchanger nozzles. The staff identified that an NRC letter dated February 29, 1996 (ADAMS Accession No. 9603060023), enclosed the staff's safety evaluation regarding the BBS request for relief (Nos. NR-18 and NR-23) from the volumetric examinations of the RHR heat exchanger nozzles for the first 10-year ISI interval. The staff further noticed that the staff's safety evaluation also discusses the previous inspection requirements which were specified in the staff's safety evaluation, dated February 3, 1995 (ADAMS Accession No. 9502130021), regarding the flaws detected from these nozzle inspections and the applicant's fracture mechanics analysis for the flaws subject to the evaluation of ASME Code, Section XI, IWB-3600.

In addition, the staff determined that the February 29, 1996, safety evaluation states that instead of the previous requirements specified in the February 3, 1995, safety evaluation, the applicant is required to perform UT examinations on a sample of RHR nozzle-to-vessel welds (one nozzle per unit) during the next inspection interval (i.e., the second interval) to provide additional assurance that these flaws have not grown and that no new service-induced indication has developed.

The staff also identified that the applicant's letter dated July 25, 2007 (ADAMS Accession No. ML072060413), describes a relief request regarding the Braidwood Units 1 and 2 RHR heat exchanger nozzle examinations for the second 10-year inspection interval. The staff further noticed that even though this 2007 relief request was withdrawn by the applicant's letter dated January 23, 2008 (ADAMS Accession No. ML080240324), the July 25, 2007, letter indicates that UT examinations were performed in September 1998 on a nozzle (1RHR-01-1RHXN1, A HX) of Braidwood Unit 1 RHR heat exchangers to fulfill the requirements specified in the February 22, 1996, NRC safety evaluation (i.e., volumetric examination of one nozzle per unit during the second ISI interval). The staff noticed that the applicant's 2007 letter also states that no appreciable flaw growth was noted from the 1998 examinations on the examined nozzle of Braidwood Unit 1.

As discussed above, it was unclear to the staff why the applicant's response does not discuss the UT examination results for the Braidwood Unit 1 RHR heat exchanger nozzle which were obtained in September 1998, as described in the applicant's letter dated July 25, 2007. It was also unclear to the staff why the applicant's response does not address any results of the UT examinations associated with the applicant's fracture mechanics analysis which are required for the RHR heat exchanger nozzles (i.e., a nozzle per unit), as specified in the staff's safety evaluation dated February 29, 1996. In addition, the staff needed clarification on whether the existing flaws are embedded inside the RHR heat exchanger nozzles without exposure to the reactor coolant in order to confirm the absence of environmental effects on flaw growth. The staff also noticed that the applicant's response did not provide the length of the bounding flaw with an as-found depth of 0.300 in. as baseline information. The staff identified that the applicant's analysis described in the LRA may not adequately address the previous volumetric examination results and the 10 CFR 54.21(c)(1)(iii) aging management basis associated with the flaw growth analysis.

By letter dated May 21, 2014, the staff issued RAI 4.7.4-1a. In Part 1 of the RAI, the staff requested that the applicant clarify why its response does not discuss the ultrasonic examination results of the Braidwood Unit 1 RHR heat exchanger nozzle which were obtained in September 1998 as documented in the applicant's relief request letter dated July 25, 2007.

In Part 2 of the RAI, the staff requested that the applicant clarify why its response does not address results of the ultrasonic examinations, which are associated with the applicant's fracture mechanics analysis and are required for the RHR heat exchanger nozzles (i.e., a nozzle per unit) as specified in the staff's February 29, 1996, safety evaluation. The staff also requested that, if all of these ultrasonic examinations have not been completed, the applicant justify why the applicant does not identify the ultrasonic examinations as part of the 10 CFR Part 54.21(c)(1)(iii) aging management basis associated with the applicant's fracture mechanics analysis.

In Part 3 of the RAI, the staff requested that the applicant provide additional information to confirm whether the previous ultrasonic examinations, including those performed in 1998, revealed any flaw growth. The staff also requested that the applicant define "no appreciable flaw growth," which was mentioned in the applicant's letter dated July 25, 2007.

In Part 4 of the RAI, the staff requested that the applicant clarify whether the existing flaws are embedded inside the RHR heat exchanger nozzles without exposure to the reactor coolant in order to confirm the absence of environmental effects on flaw growth. In addition, the staff requested that the applicant describe the length of the bounding flaw in comparison with the inner diameter of the nozzle as baseline information.

By letter dated June 16, 2014, the applicant responded to RAI 4.7.4-1a. In its response the applicant indicated that it interpreted Part 3 of RAI 4.7.4-1 as a request to provide the results of the most recent (i.e., last performed) examinations for the period between 1991 and 1994 which were addressed in the staff's February 3, 1995, safety evaluation regarding the fracture mechanics analysis of the observed flaws. The applicant clarified that the 1998 ultrasonic examination results were not included in the response to RAI 4.7.4-1 based on this interpretation.

In its response to Part 2 of RAI 4.7.4-1a, the applicant stated that additional ultrasonic examinations after 1994 were performed on RHR heat exchanger nozzles in accordance with the staff's safety evaluation dated February 29, 1996. The applicant also clarified that the ultrasonic examinations were performed on one nozzle per unit at Byron Units 1 and 2 and Braidwood Unit 1 in the second ISI interval, as specified in the 1996 safety evaluation. The applicant stated that these examinations confirmed that there was no flaw growth from the first to the second ISI interval.

In addition, the applicant stated that an ultrasonic examination of one Braidwood Unit 2 RHR heat exchanger nozzle was planned for the spring 2008 refueling outage, which was the last refueling outage in the second ISI interval for the unit. The applicant also stated that because an ultrasonic examination of these nozzles requires extensive labor resources, radiation exposure to the examiners, and significant cost without a commensurate increase in quality or public safety, a relief request was submitted to the staff in the letter dated July 25, 2007. The applicant further indicated that the submitted letter asked a relief from the ASME Code, Section XI requirement to perform ultrasonic examinations on the RHR heat exchanger nozzles based on the alternative visual examination requirements in ASME Code Case N-706. In addition, the applicant indicated that since the staff endorsed ASME Code Case N-706 in 2007 after the submittal of the relief request and all Braidwood Unit 2 RHR heat exchanger nozzles had been ultrasonically examined at least once during the period between 1991 and 1994, thereby satisfying ASME Code Case N-706 requirements, an ultrasonic examination of the Braidwood Unit 2 RHR heat exchanger nozzle in the second interval was no longer required in the spring 2008 refueling outage. The applicant also stated that, on January 23, 2008, a followup letter was submitted to the staff withdrawing the July 2007 relief request.

In its response to Part 2, the applicant also confirmed that the second interval examinations described above found no new flaws. The applicant further indicated that these ultrasonic examination results are consistent with the conclusions of the applicant's fracture mechanics analysis and demonstrate that the RHR nozzle weld flaw growth would be inconsequential (a total growth of less than 0.001 in.) for the 60-year period of operation.

In its response to Part 3 of RAI 4.7.4-1a, the applicant stated that the comparisons of the ultrasonic examination results between the first and second ISI intervals concluded that there was no observed flaw growth greater than the repeatability variances of examination equipment and techniques. The applicant also clarified that the term "no appreciable flaw growth" in the July 25, 2007, letter was intended to explain that any dimensional differences between the flaw examination results between the first and second intervals were small and within the repeatability variances of the examinations. The applicant further indicated that the repeatability variances resulted from factors such as slight variations in the transducer placement angles, orientation, and surface contact during the scanning process, and slight differences in the scanners, search units, and gain levels.

In its response to Part 4 of RAI 4.7.4-1a, the applicant stated that the first interval examinations performed from 1991 through 1994 found that all indications were subsurface flaws, not open to the internal and external surface of the nozzle, and, therefore, not exposed to reactor coolant. The applicant also stated that these flaws were determined to be fabrication flaws. The applicant further clarified that the examinations performed in the second ISI interval found that none of the flaws had grown and the flaws remained subsurface. In addition, the applicant stated that the length of the bounding flaw was 0.8 in. and the inside nozzle diameter is 13.075 in., indicating that the flaw length was not significant compared to the nozzle circumference.

The staff finds the applicant's response acceptable because the applicant confirmed that (1) ultrasonic examinations were conducted on RHR heat exchanger nozzles at Byron Units 1 and 2 and Braidwood Unit 1 during the second ISI interval, (2) these examination results demonstrated that no flaw growth occurred from the first to the second ISI interval and no new flaws were detected in the second interval, (3) the applicant relied on ASME Code Case N-706 to justify why the ultrasonic examination planned for the second interval of Braidwood Unit 2 was not performed, (4) "no appreciable flaw growth" addressed in the July 25, 2007, letter was intended to explain that there was no observed flaw growth greater than the repeatability variances of the ultrasonic examinations, and (5) the ultrasonic examinations performed during the first and second intervals confirmed that all indications were subsurface flaws, and not exposed to the reactor coolant environment. Therefore, the staff's concern described in RAIs B.4.7.4-1 and B.4.7.4-1a are resolved.

Thus, the staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue flaw growth on the intended functions of the RHR heat exchanger nozzles will be adequately managed for the period of extended operation.

Additionally, LRA Section 4.7.4 meets the acceptance criteria in SRP-LR Section 4.7.2 because the applicant appropriately evaluated the TLAA for the flaws of RHR heat exchanger nozzles, consistent with the CLB, and fatigue flaw growth in these nozzles will be adequately managed by the Fatigue Monitoring program for the period of extended operation.

4.7.4.3 UFSAR Supplement

LRA Section A.4.7.4 provides the UFSAR supplement summarizing the flaw growth analysis for the RHR heat exchanger tube side nozzles. The staff reviewed LRA Section A.4.7.4 consistent with the review procedures in SRP-LR Section 4.7.3.2. The review procedures state that the reviewer verifies that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA. The review procedures also state that each such summary description is reviewed to verify that it is appropriate. The review procedures further state that the description should contain information that the TLAA has been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff determines that the applicant met the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue flaw growth in the RHR heat exchanger tube side inlet and outlet nozzles, as required by 10 CFR 54.21(d).

4.7.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue flaw growth on the intended functions of the RHR heat exchanger tube side inlet and outlet nozzles will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.5 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis

4.7.5.1 Summary of Technical Information in the Application

LRA Section 4.7.5 describes the applicant's TLAA for fatigue crack growth in the RCP motor flywheels. The LRA states that fatigue is an aging effect that was analyzed due to the possibility of flywheel failure, which could create missiles and damage the RCP seals or other pressure boundary components. Accordingly, TS 5.5.7 requires the applicant to periodically inspect the integrity of the flywheels using either ultrasonic or surface tests. Two of the RCP motor flywheels must be inspected at 10-year intervals coinciding with the ISI schedule specified by

ASME Code, Section XI, and all of the other flywheels must be inspected at an interval not to exceed 20 years. The LRA states that Westinghouse reports WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," dated November 1996, and WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination," dated October 2003, establish the bases for the 10- and 20-year inspection intervals, respectively. The LRA states that both inspection intervals are based on fatigue crack growth analyses that assume 6,000 RCP start-stop cycles, which is more than the greatest number of cycles the applicant projects for any RCP motor flywheel to experience in 60 years of operation. The applicant dispositioned the TLAA for RCP motor flywheel fatigue crack growth in accordance with 10 CFR 54.21(c)(1)(i) to demonstrate that the analyses remain valid for the period of extended operation.

4.7.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for RCP motor flywheel fatigue crack growth and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3.1.1. These procedures state that the applicant should show that the existing analysis bounds the period of extended operation, so that no reanalysis is necessary.

The staff found that there are a total of 18 RCP motor flywheels at Byron and Braidwood, two of which are spares. On September 20, 2001, and September 16, 2010, the staff issued license amendments modifying TS 5.5.7. These amendments impose the current 10- and 20-year inspection intervals for the RCP motor flywheels, respectively. The 10-year inspection interval is based on the staff's prior approval of WCAP-14535A; the 20-year inspection interval is based on the staff's prior approval of WCAP-15666-A. The TSs require different inspection frequencies because two of the RCP motor flywheels were originally designed and built for the cancelled Marble Hill Nuclear Generating Station (serial numbers 4S88P961 and 1S88P961), and these flywheels are not interchangeable with the Byron and Braidwood RCP motors evaluated in WCAP-15666-A. The staff reviewed both topical reports and confirmed that the applicable aging effect considered in the analyses is cracking due to fatigue. The staff also confirmed that the only time-limited assumption involved in the analyses is the number of RCP motor start-stop cycles, which are inputs to the fatigue crack growth analyses.

To demonstrate that the WCAP-14535A and WCAP-15666-A analyses bound the period of extended operation, LRA Section 4.7.5 states that the applicant projected the number of RCP motor start-stop cycles through 60 years. LRA Tables 4.3.1-1 and 4.3.1-4 identify these cycles as operational transients. According to the methodology described in LRA Section 4.3.1, the applicant determined the number of 60-year projected cycles by adding the product of the cycle projection rate and the remaining number of years to the number of baseline cycles, where the cycle projection rate is based on past operating data. As a result, the applicant projects 1,755 RCP motor start-stop cycles for Byron Unit 1, 1,545 cycles for Byron Unit 2, 1,125 cycles for Braidwood Unit 1, and 1,035 cycles for Braidwood Unit 2.

By reworking the applicant's formula for calculating the number of 60-year projected cycles, the staff developed a formula for the cycle projection rate. This rate is equal to the difference of the 60-year projected cycles and the baseline cycles divided by the number of remaining years. The staff calculated the number of remaining years for each unit and then input these values, along with the values in LRA Tables 4.3.1-1 and 4.3.1-4 for the baseline cycles and 60-year projected cycles, into the reworked cycle projection rate formula. As a result, the staff determined that the applicant used approximately 21 cycles per year for the Byron Unit 1 projection, 17 cycles per year for the Byron Unit 2 projection, 20 cycles per year for the

Braidwood Unit 1 projection, and 14 cycles per year for the Braidwood Unit 2 projection. The staff compared these values with recent Byron and Braidwood reactor power status reports and determined that the applicant's cycle projection rates are reasonable; therefore, the staff determined that they are acceptable to demonstrate that the existing analyses bound the period of extended operation.

Although the applicant's projections for the number of RCP motor start-stop cycles are adequate, the staff noticed that past RCP motor flywheel inspection results could invalidate the existing analyses if the inspections detected a flaw and there is evidence of an actual crack growth rate that is greater than the rate assumed in WCAP-14535A and WCAP-15666-A. TS 5.5.7 requires the applicant to periodically inspect the RCP motor flywheels; however, the staff noticed that the LRA does not provide any results from these past inspections. By letter dated February 26, 2014, the staff issued RAI 4.7.5-1, requesting that the applicant summarize the results of the past ISIs of the RCP motor flywheel components. If flaws were detected, the staff requested the applicant to quantify any growth and provide a comparison against the crack growth rates used in WCAP-14535A and WCAP-15666-A.

The applicant responded to RAI 4.7.5-1 by letter dated March 28, 2014. The applicant provided the most recent inspection results for all 18 of its RCP motor flywheels. If these results had recordable indications, then the applicant also provided the previous inspection results for comparison. According to this information, rounded and linear indications have been detected in some of the RCP motor flywheels. However, the applicant stated that all of the recorded indications meet the applicable acceptance criteria from WCAP-14535A and WCAP-15666-A, and there have been no indications of fatigue crack growth between inspections. The staff reviewed the inspection results provided by the applicant and determined that they do not demonstrate any fatigue-induced growth of flaws in the RCP motor flywheels. Therefore, the staff finds the applicant's response acceptable because there is no actual crack growth data that would invalidate the fatigue crack growth rates assumed in WCAP-14535A and WCAP-15666-A. The staff's concern described in RAI 4.7.5-1 is resolved.

Based on the adequacy of the applicant's cycle projections and the lack of actual fatigue crack growth, the staff finds that the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for RCP motor flywheel fatigue crack growth remain valid for the period of extended operation. This demonstration also meets the acceptance criteria in SRP-LR Section 4.7.2.1.

4.7.5.3 UFSAR Supplement

LRA Section A.4.7.5 provides the UFSAR supplement summarizing the TLAA for RCP motor flywheel fatigue crack growth. The staff reviewed LRA Section A.4.7.5 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the applicant is to provide a summary description for its evaluation of each TLAA. The SRP-LR also states that the summary description should contain information on the disposition of the TLAA for the period of extended operation and be appropriate such that later changes can be controlled by 10 CFR 50.59.

As described in LRA Section 4.7.5, the TLAA applies to two separate fatigue crack growth analyses. One analysis, which is based on WCAP-14535A, establishes a 10-year inspection interval for RCP motor serial numbers 4S88P961 and 1S88P961. The other analysis, which is based on WCAP-15666-A, establishes a 20-year inspection interval for the other flywheels. However, the staff concluded that the summary description in LRA Section A.4.7.5 only addressed the 10-year inspection interval, and it did not address the 20-year inspection interval. As such, the staff determined that the summary description did not cover the full scope of the TLAA or clearly identify which inspection intervals apply to which RCP motor flywheels. For these reasons, the staff determined that the applicant's summary description would not facilitate control of later changes to the TLAA by 10 CFR 50.59. By letter dated February 26, 2014, the staff issued RAI 4.7.5-2 requesting the applicant to revise LRA Section A.4.7.5 to clearly identify each of the RCP motor flywheels and specify which topical report and corresponding inspection frequency apply to each.

By letter dated March 28, 2014, the applicant responded to RAI 4.7.5-2 by amending the summary description in LRA Section A.4.7.5. The applicant subsequently retracted this amendment by letter dated June 30, 2014; however, by letter dated July 15, 2014, the applicant re-submitted an identical amendment to LRA Section A.4.7.5. The amended summary description specifies the serial numbers for the RCP motor flywheels that are subject to the 10-year inspection interval and states that the 20-year inspection interval applies to all of the other flywheels. The revised summary description also states that the fatigue crack growth analyses in WCAP-14535A and WCAP-15666-A provide the bases for the 10- and 20-year inspection intervals, respectively. The staff reviewed these revisions and finds them acceptable because they clearly identify all of the RCP motor flywheels addressed in the TLAA and their respective inspection requirements consistent with TS 5.5.7. The staff confirmed that the revisions also identify that WCAP-14535A and WCAP-15666-A provide the bases for the inspection requirements, which the applicant demonstrated to remain valid for the period of extended operation. Therefore, the staff's concern described in RAI 4.7.5-2 is resolved.

Based on its review of the UFSAR supplement, as amended by letter dated July 15, 2014, the staff finds that LRA Section A.4.7.5 meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for RCP motor flywheel fatigue crack growth, as required by 10 CFR 54.21(d).

4.7.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA for RCP motor flywheel fatigue crack growth remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.6 Byron Unit 2 Pressurizer Seismic Restraint Lug Flaw Evaluation

4.7.6.1 Summary of Technical Information in the Application

LRA Section 4.7.6 states that, in September of 2005, an indication exceeding the acceptance standards of ASME Section XI, Subarticle IWB-3500, 1989 Edition was found on a Byron Unit 2 pressurizer seismic lug. The LRA also states that investigation concluded that the indication was not service induced, but rather was due to lack of fusion in the original weld. The LRA further states that a flaw growth analysis was performed in accordance with ASME Section XI, Subarticle IWB-3600, 1989 Edition, which concluded that the indication size will remain within acceptable limits for the current remaining licensed operating period. The LRA also states that this analysis assumed input transients for the current licensed operating period based on

40 years of operation. Therefore, the applicant concluded that the Byron Unit 2 pressurizer seismic restraint lug flaw evaluation is a TLAA.

The applicant dispositioned the Byron Unit 2 pressurizer seismic restraint lug flaw evaluation in accordance with 10 CFR 54.21(c)(1)(iii), to demonstrate that the effects of aging on the intended function(s) will be adequately managed by the Fatigue Monitoring program, for the period of extended operation.

4.7.6.2 Staff Evaluation

The staff reviewed LRA Section 4.7.6 and the TLAA for the Byron Unit 2 pressurizer seismic restraint lug flaw evaluation to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed consistent with the CLB for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the applicant proposes to manage the aging effects associated with the TLAA by an AMP in a manner as described in the IPA in 10 CFR 54.21(a)(3). The SRP-LR also states that the staff verifies that the effects of aging on the intended function(s) are adequately managed consistent with the applicant's CLB for the period of extended operation.

The staff also reviewed the applicant's flaw growth analysis for Byron Unit 2 pressurizer seismic lug (ML080580263). The staff noticed that the design transient used in the evaluation is the auxiliary spray actuation transient, which is identified in LRA Table 4.3.1-2. The staff also found that the applicant credited its Fatigue Monitoring Program to manage the effects of pressurizer seismic restraint lug flaw growth on the component fatigue life, by monitoring the transient cycles to assure that the assumed number of transient cycles are not exceeded during the period of extended operations. The staff's review of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.24. The staff determined that the cycle counting method will ensure that the fatigue analysis remains valid by ensuring the assumed number of transients used in the analysis is not exceeded.

Based on its review, the staff finds that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that flaw growth of the Byron Unit 2 pressurizer seismic restraint lug flaw will be adequately managed for the period of extended operation. Additionally, the applicant's demonstration meets the acceptance criteria in SRP-LR Section 4.7.3.1.3 because the Fatigue Monitoring Program will monitor transient cycles used in the analysis to ensure that, if a transient limit is approached, corrective action is taken prior to exceeding a transient limit.

4.7.6.3 UFSAR Supplement

LRA Section A.4.7.6 provides the UFSAR supplement summarizing the Byron Unit 2 pressurizer seismic restraint lug flaw evaluation. The staff reviewed LRA Section A.4.7.6 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.7.6 meets the acceptance criteria in SRP-LR Section 4.7.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the Byron Unit 2 pressurizer seismic restraint lug flaw evaluation as required by 10 CFR 54.21(d).

4.7.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that flaw growth of the Byron Unit 2 pressurizer seismic restraint lug flaw will be adequately managed by the Fatigue Monitoring Program during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the Byron Unit 2 pressurizer seismic restraint lug flaw evaluation, as required by 10 CFR 54.21(d).

4.7.7 Braidwood Unit 2 Feedwater Pipe Elbow Crack Growth Evaluation

4.7.7.1 Summary of Technical Information in the Application

LRA Section 4.7.7 describes the applicant's TLAA for the Braidwood Unit 2 feedwater pipe elbow crack growth evaluation. The applicant stated that an axial indication was identified on a Braidwood Unit 2, 16-in. main feedwater line elbow downstream of the feedwater regulating valves. The applicant performed a crack growth analysis, in accordance with ASME Section XI, Subarticle IWB-3600, which concluded that the crack size will remain within the acceptable limits during the 40-year life of the plant. The LRA states that the analysis assumed RCS heatup and cooldown, reactor trip transients, and reactor trips with RCS cooldown transients over the 40-year life of the plant and has therefore been identified as a TLAA requiring evaluation for the period of extended operation. The LRA also states that the number of transients assumed in the analysis bounds the number of transients projected to occur through the period of extended operation as discussed in LRA Section 4.3.1.

The applicant dispositioned the Braidwood Unit 2 feedwater pipe elbow crack growth evaluation in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed by the Fatigue Monitoring program, for the period of extended operation.

4.7.7.2 Staff Evaluation

The staff reviewed LRA Section 4.7.7 and the TLAA for the Braidwood Unit 2 feedwater pipe elbow crack growth evaluation to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed consistent with the CLB for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the applicant proposes to manage the aging effects associated with the TLAA by an AMP in the same manner as described in the IPA in 10 CFR 54.21(a)(3). The SRP-LR also states that the reviewer reviews the applicant's AMP to verify that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation.

The staff reviewed LRA Table 4.3.1-4, which provides the baseline and 60-year cycle projections for RCS transients. The staff found that the applicant will use the Fatigue Monitoring program to ensure that the numbers of transients will not be exceeded during the period of extended operation and the numbers of transients assumed in the analysis bounds the number of transients projected to occur through the period of extended operation. The staff also reviewed the applicant's TLAA evaluation basis and compared the number of transients input to the crack growth evaluation with the 60-year projections from the LRA Table 4.3.1-4, and determined that the numbers of transient cycles assumed in the crack growth analysis are bounded by their 60-year projections.

Bases on this review, the staff finds the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the Braidwood Unit 2 feedwater pipe elbow will be adequately managed consistent with the CLB for the period of extended operation.

In addition, the TLAA meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the ASME Section XI crack growth analyses will be managed by the Fatigue Monitoring program, which will monitor transient cycles and require corrective action prior to exceeding the number of transient cycles used in the evaluations which support these conclusions.

4.7.7.3 UFSAR Supplement

LRA Section A.4.7.7 provides the UFSAR supplement which summarizes the Braidwood Unit 2 feedwater pipe elbow crack growth evaluation. The staff reviewed LRA Section A.4.7.7 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that LRA Section A.4.7.7 meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the Braidwood Unit 2 feedwater pipe elbow crack Growth Evaluation as required by 10 CFR 54.21(d).

4.7.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that flaw growth of the Braidwood Unit 2 feedwater pipe elbow will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.8 Analyses Supporting Flaw Evaluations of Primary System Components

4.7.8.1 Summary of Technical Information in the Application

Fatigue Crack Growth Analysis. LRA Section 4.7.8 states that BBS have performed preemptive flaw evaluations on primary system components (such as the reactor vessel, pressurizer, primary steam generator subcomponents, and primary coolant components) consistent with ASME Section XI, Subarticle IWB-3600. The LRA further states flaw evaluations were performed consistently with the methodologies in WCAP-11063, "Handbook on Flaw Evaluations for Byron Unit 1 and 2 Steam Generators and Pressurizers," earlier in plant life and are now performed consistent with those in WCAP-12046, "Handbook on Flaw Evaluations for the Byron and Braidwood Units 1 and 2 Reactor Vessels." LRA Section 4.7.8 further states that the handbooks for flaw evaluation methodology are based on crack growth rate analyses using the design-based transients as inputs for each of the evaluated components to provide crack growth rate reference curves. Since the flaw evaluation handbooks are based on analyses that have time-limited inputs (e.g., number of design transient cycles assumed over 40 years), these analyses supporting flaw evaluations of primary system components have been identified as TLAAs.

The LRA also states that the numbers of transients used to develop the crack growth rate reference curves bound the numbers of transients in the 60-year projections provided in LRA Section 4.3.1.

The applicant dispositioned this TLAA for Byron and Braidwood, Units 1 and 2, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed by the Fatigue Monitoring (B.3.1.1) program, for the period of extended operation.

<u>Fracture Toughness Input to Analyses—Irradiation Embrittlement of Reactor Vessel Beltline and Extended Beltline Components</u>. LRA Section 4.7.8 states that Byron and Braidwood performed flaw evaluations on reactor vessels consistent with ASME Code, Section XI, Subarticle IWB-3600. The LRA further states the flaw evaluations were performed consistently with the methodologies in WCAP-11063 earlier in plant life and are now performed consistent with those in WCAP-12046. LRA Section 4.7.8 further states that these methodologies are based on analyses which use fracture toughness as an input. The applicant stated that the loss of fracture toughness occurs in the portions of the reactor vessel exposed to neutron irradiation embrittlement over the life of the reactor vessel, and therefore the analyses that use fracture toughness as an input supporting the flaw evaluations have been identified as TLAAs.

The applicant dispositioned this TLAA for Byron and Braidwood, Units 1 and 2, in accordance with 10 CFR 54.21(c)(1)(i), such that the ASME Section XI analyses supporting the flaw evaluations for the reactor vessel remain valid during the period of extended operation.

4.7.8.2 Staff Evaluation

The LRA provides two separate analyses to support flaw evaluations of primary system components. One analysis uses transient counts as the time-dependent parameter, whereas the second analysis uses neutron fluence as the time-dependent parameter. As described above, the applicant dispositioned these analyses as two separate TLAAs in accordance with 10 CFR 54.21(c).

<u>Fatigue Crack Growth Analysis</u>. The staff reviewed LRA Section 4.7.8 for the applicant's TLAA for fatigue crack growth analyses for Byron and Braidwood, Units 1 and 2, to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the applicant proposes to manage the aging effects associated with the TLAA by an AMP in the same manner as described in the IPA in 10 CFR 54.21(a)(3). The SRP-LR also states that the staff reviews the applicant's AMP to verify that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation. In addition, the SRP-LR requires that a license renewal applicant must identify the SCs associated with the TLAA.

The staff concluded that the methodology in WCAP-11063 and WCAP-12046 uses inputs such as: flaw location, initial size, and the final acceptable size; the base material; and the number of design transient cycles to calculate conservative flaw growth on reactor vessel, pressurizer, primary steam generator subcomponents and primary coolant components. These provide crack growth rate reference curves, which are based on the above factors and that the crack growth rate reference curves provide simplified conclusions as to whether the flaw will propagate to an unacceptable size in 10, 20, 30, or 40 years. The staff also noticed that each of the flaw evaluations used one or more of these curves to demonstrate that flaws will not propagate to unacceptable sizes prior to 40 years.

The staff found that the applicant will use the Fatigue Monitoring program to ensure that the numbers of transients used in these curves will not be exceeded during the period of extended operation. However, it was unclear to the staff which transients were used in the flaw evaluation methodology to confirm that the transients are within the scope of the Fatigue Monitoring program. By letter dated February 6, 2014, the staff issued RAI 4.7.8-1, requesting that the applicant provide the transients that support the ASME Section XI crack growth analyses.

By letter dated March 10, 2014, the applicant responded to RAI 4.7.8-1. The applicant provided the thermal and pressure transients and the number of design transient cycles assumed in the flaw evaluations that support the ASME Section XI crack growth analyses. The applicant stated that these transients are monitored by the Fatigue Monitoring program. The applicant further stated that one of the transients assumed in the flaw evaluation analyses uses a design transient cycle value that is more limiting than the CLB Cycle Limit presented in LRA Tables 4.3.1-1 and 4.3.1-4. The CLB Cycle Limit in LRA Tables 4.3.1-1 and 4.3.1-4 for the Excessive Bypass Feedwater Flow transient is 40 cycles. However, the applicant identified that the steam generator flaw evaluation assumes a design transient cycle limit of 30. The applicant stated that LRA Tables 4.3.1-1 and 4.3.1-4 have been updated to reflect the more conservative cycle limit of 30 cycles for the Excessive Bypass Feedwater Flow transient. The staff confirmed that the transients listed in the RAI response are included in LRA Tables 4.3.1-1 and 4.3.1-4. The staff finds the applicant's response acceptable because the design transients assumed for the flaw evaluations are included in LRA Section 4.3 tables and will be monitored by the Fatigue Monitoring program, and also because the applicant updated LRA Tables 4.3.1-1 and 4.3.1-4 to reflect the conservative cycle limits for the transients. The staff's concern in RAI 4.7.8-1 is resolved.

The staff also noticed that the LRA Section 4.7.8 states that the fatigue crack growth analyses are pre-emptive. However, it is not evident whether these analyses were performed in evaluation of actual flaws detected in Class 1 components at the plant or in evaluation of flaws that were assumed to occur in the components. Specifically, the applicant did not clearly identify which reactor pressurize vessel (RPV), steam generator, pressurizer, or RCPB piping components had contained flaws and were analyzed in accordance with the generic flaw evaluation methodology in both WCAP-11063 or WCAP-12046. By letter dated August 20, 2014, the staff issued RAI 4.7.8-2, requesting that the applicant describe the RPV, steam generator, pressurizer, and RCPB flaws that were evaluated with the flaw evaluation criteria in WCAP-11063 or in WCAP-12046 and to identify the NRC safety evaluation references for the approval of these flaws.

By letter dated September 5, 2014, the applicant responded to RAI 4.7.8-2. The applicant stated that it reviewed its OE and its regulatory correspondence database to identify flaws at Byron and Braidwood Station that were evaluated with the methodology and acceptance criteria in WCAP-11063 or in WCAP-12046. The applicant provided a table of the results of its review, which included references to the applicable NRC safety evaluation. The staff reviewed the results provided by the applicant and confirmed that the flaws at BBS were evaluated consistent with the methodology and acceptance criteria of the two WCAP reports. The staff finds the applicant's response acceptable because the applicant confirmed that the analyses described in LRA Section 4.7.8 were used to provide a safety determination for actual flaws identified at BBS. Because the analyses were performed on actual flaws, the staff finds acceptable for the applicant to use its Fatigue Monitoring program to monitor the transient cycles assumed in the analyses, such that the TLAA evaluation of the primary system fatigue crack growth analyses is consistent with 10 CFR 54.21(c)(1)(iii). The staff's concern in RAI 4.7.8-2 is resolved.

The staff finds the applicant demonstrated, pursuant to 10 CFR 54.12(c)(1)(iii), that the impacts of fatigue crack growth on the intended RCPB function of the components analyzed for in the flaw evaluations will be adequately managed for the period of extended operation.

Additionally, the TLAA meets the acceptance criteria in SRP-LR Section 4.7.3.1.3 because the ASME Section XI flaw evaluations will be managed by the Fatigue Monitoring program, which will monitor the transient cycles and require corrective action prior to exceeding the numbers of transient cycles used in the evaluations which support these conclusions.

<u>Fracture Toughness Input to Analyses—Irradiation Embrittlement of Reactor Vessel Beltline and Extended Beltline Components</u>. The staff reviewed LRA Section 4.7.8 and the TLAA for the flaw evaluations of the reactor vessel to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. For the flaw evaluations that evaluate the impact of increasing neutron fluence on the fracture toughness values used in the analyses, the staff reviewed the TLAA to demonstrate that the treatment of fracture toughness values used in the analyses will remain valid for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which state that the applicant justifies that the existing analyses remain valid and bounding for the period of extended operation. The SRP-LR further states that the applicant should show that relevant aging effects for the period of extended operation are already addressed in the conditions and assumptions in the analyses. The SRP-LR also states that the applicant should show that the acceptance criteria of the analyses are maintained to provide reasonable assurance that the intended function(s) is maintained for renewal.

The applicant stated that the methodology in WCAP-12046 shows that the flaw evaluation charts for the active beltline region are valid for RT_{NDT} less than 200 °F. LRA Section 4.2 describes the applicant's TLAA on reactor vessel neutron embrittlement analysis and provides the projected RT_{NDT} for Byron and Braidwood at 57 EFPY. The applicant stated that the projected RT_{NDT} for the RPV beltline components at 57 EFPY are less than 200 °F, and therefore, the flaw evaluation charts in WCAP-12046 are still applicable for the period of extended operation.

The staff noticed that flaw evaluations performed in accordance with ASME Section XI, Subsection IWB-3600, Appendix C, calculate K_{Ic} and K_{Ia} stress intensity factors as a function of a component's ART (end-of-life RT_{NDT} or RT_{PTS} values), which are fluence-dependent. The staff reviewed the information provided in LRA Section 4.2 and confirmed that the projected RT_{NDT} are less than 200 °F at the end of the period of extended operation for all of the beltline region materials of BBS. The staff noticed that the flaw evaluations performed in accordance with WCAP-12046 assumed a 200 °F end-of-life RT_{NDT} value for the components in the evaluations.

The staff's evaluation of the RT_{NDT} calculations and LRA Section 4.2 is documented in SER Section 4.2. The staff finds the applicant's justification for the active beltline acceptable because there is conservative margin between the projected RT_{NDT} values described in Section 4.2 and the limit of 200 °F that would invalidate the flaw evaluation charts in WCAP-12046.

The applicant stated that the next material below the active beltline in the reactor vessel is the lower shell to bottom head ring circumferential weld. The applicant stated that calculated fluence on the weld is approximately 4×10^{15} n/cm^2, which would result in an increase in RT_{PTS} of 2 °F based on conservative calculations. The applicant stated that the effects of fluence will continue to be negligible. Above the active beltline, the applicant stated that the increase in RT_{PTS} for 57 EFPY due to irradiation at the nozzle shell forgings and associated welds is approximately 10 to 20 °F. The applicant also states that the next material above the active beltline and the inlet and outlet nozzles is the vessel flange-to-nozzle shell forging circumferential weld. The applicant stated that the fluence in this weld is projected to be below 1×10^{17} n/cm^2, and therefore, the embrittlement effects are considered negligible. The applicant also states that, as provided in LRA Section 4.2.3, the highest value of RT_{PTS} from all the extended beltline regions is 90 °F. The applicant stated that, based on RT_{PTS} of 90 °F and the limiting temperature from the bounding transient, the calculated K_{Ic} and K_{Ia} (fracture toughness) value is greater than 200 ksi-in$^{1/2}$. The applicant stated that the flaw evaluation charts in WCAP-12046 remain valid for the period of extended operation because the flaw evaluation charts for the extended baseline region are determined based on an upper-shelf limit of 200 ksi-in$^{1/2}$.

The staff also reviewed the RT_{PTS} calculations for the extended beltline regions. The staff finds the applicant's justification acceptable because, for the material below the active beltline, the change in RT_{PTS} would be negligible based on the calculated fluence on the material. For the material above the active beltline, the staff finds the justification acceptable because calculated K_{Ic} and K_{Ia} based on the most bounding conditions and inputs would result in a value greater than the limit of 200 ksi-in$^{1/2}$ that would invalidate the flaw evaluation charts in WCAP-12046.

The staff finds that the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the existing analyses are valid for the period of extended operation because the existing analyses utilize fracture toughness values that bound those projected for the end of the period of operation. Additionally, the TLAA meets the acceptance criteria in SRP-LR Section 4.7.3.1.1 because the existing analyses will remain valid for the period of extended operation.

4.7.8.3 UFSAR Supplement

LRA Section A.4.7.8 provides the UFSAR supplement summarizing the analyses supporting flaw evaluations of primary system components. The staff reviewed LRA Section A.4.7.8 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the information to be included in the UFSAR supplement should include a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that the applicant meets the acceptance criteria in SRP-LR Section 4.7.2.2 for the TLAA evaluation of the primary system fatigue crack growth analyses. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of the primary system fatigue crack growth analyses, as required by 10 CFR 54.21(d).

Based on its review of the UFSAR supplement, the staff finds that the applicant meets the acceptance criteria in SRP-LR Section 4.7.2.2 for the TLAA evaluation for the loss of fracture toughness input to the flaw evaluations. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation for the loss of fracture toughness input to the flaw evaluations, as required by 10 CFR 54.21(d).

4.7.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant acceptably demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the primary system fatigue crack growth analyses will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation of the primary system fatigue crack growth analyses, as required by 10 CFR 54.21(d).

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the loss of fracture toughness input to the flaw evaluations 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 loss of fracture toughness input to the flaw evaluations, as required by 10 CFR 54.21(d).

4.8 Conclusion

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant provided a sufficient list of TLAAs, as defined in 10 CFR 54.3, and that the applicant demonstrated the following:

- The TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i).
- The TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii).
- The effects of aging on the intended functions will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii).

The staff also reviewed the UFSAR supplement for the TLAAs and finds that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes, as required by 10 CFR 54.21(c)(2), that no plant-specific, TLAA-based exemptions are in effect.

With regard to these matters, the staff concludes that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB. Additionally, any changes made to the CLB to comply with 10 CFR 54.29(a) are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In accordance with Title 10 of the *Code of Federal Regulations* Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. Exelon Generation Company, LLC and the staff of the United States (U.S.) Nuclear Regulatory Commission (NRC) (the staff) will meet with the subcommittee and the full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and SER, the full committee will issue a report discussing the results of the review. An update to this SER will include the ACRS report and the staff’s response to any issues and concerns reported.

SECTION 6

CONCLUSION

The staff of the United States (U.S.) Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, in accordance with NRC regulations and NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated December 2010. Title 10 of the *Code of Federal Regulations* (10 CFR) 54.29, "Standards for Issuance of a Renewed License," sets the standards used for issuing 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 notes that any requirements of 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," Subpart A, "National Environmental Policy Act—Regulations Implementing Section 102(2)," will be documented in separate supplements for Byron and Braidwood to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)."

APPENDIX A

BYRON STATION, UNITS 1 AND 2, AND BRAIDWOOD STATION, UNITS 1 AND 2, LICENSE RENEWAL COMMITMENTS

During the review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, (BBS) license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff), Exelon Generation Company, LLC, made commitments related to aging management programs (AMPs) to manage aging effects of structures and components.

LRA Section A.1.0, “Introduction,” states “The application for a renewed operating license is required by 10 CFR 54.21(d) to include a FSAR Supplement. This Appendix [as revised by supplements, amendments, and RAI responses], which includes the following sections, comprises the FSAR supplement….” It also states “…Section A.5 contains the License Renewal Commitment List.” Therefore LRA Appendix A, as revised by supplements, amendments, and RAI responses, is considered to be the updated final safety analysis report (UFSAR) supplement as discussed in two proposed license conditions in SER Section 1.7, “Summary of Proposed License Conditions.”

The following table lists the commitments, as well as the implementation schedules and the sources for each commitment, as agreed to by the applicant and by the staff.

Explanatory notes (e.g., “Note 1”) within this table provide the basis for station-specific differences as follows:

- Note 1 – Enhancement at one Station only; other Station currently performs activity
- Note 2 – Design difference
- Note 3 – Enhancement due to operating experience

Implementation schedules for Byron, Unit 1 and Unit 2, and Braidwood, Unit 1 and Unit 2, differ according to the start of the respective period of extended operation for each unit. The dates for the start of these respective periods of extended operation for the Byron and Braidwood Units are as follows below and apply to the “Implementation Schedule” column in the table:

- Byron Unit 1, October 31, 2024
- Byron Unit 2, November 6, 2026
- Braidwood Unit 1, October 17, 2026
- Braidwood Unit 2, December 18, 2027

The commitment implementation schedules in this table, as discussed in SER Section 1.7, reflect the applicant’s response to RAI A.1-1 by letter RS-14-216 dated December 15, 2014, and allow time for NRC inspection of commitment implementation prior to a unit’s entry into its respective period of extended operation.

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD is an existing program that will be enhanced to: 1. Conduct a visual inspection of the accessible portions of the ASME Class 2 reactor vessel flange leakage monitoring tube every other refueling outage. 2. Perform nondestructive examination of the five (5) centermost control rod drive mechanism (CRDM) housing penetrations to determine the thermal sleeve centering tab wear depth on the CRDM housing penetration inner diameter wall. On each unit, these CRDM housings will be examined at least once during the 10-year period prior to the period of extended operation, and on a 10-year frequency during the period of extended operation.	A.2.1.1	Program to be enhanced no later than 6 months prior to the period of extended operation. Inspections prior to the period of extended operation specified in Enhancement 2 will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-15-067 02/11/2015
2	Existing Water Chemistry program is credited.	A.2.1.2	Ongoing	LRA
3	Reactor Head Closure Stud Bolting is an existing program that will be enhanced to: 1. Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.	A.2.1.3	Program to be enhanced no later than six months prior to the period of extended operation.	LRA Exelon letter RS-13-247 11/5/2013 Exelon letter RS-13-285 12/19/2013
4	Existing Boric Acid Corrosion program is credited.	A.2.1.4	Ongoing	LRA
5	Existing Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program is credited.	A.2.1.5	Ongoing	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
6	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) is a new program that manages the aging effects of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250°C (482°F). The program will include a screening methodology to determine component susceptibility to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For "potentially susceptible" components, thermal aging embrittlement management will be accomplished through either, qualified visual inspections, such as enhanced visual examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation.	A.2.1.6	Program to be implemented no later than six months prior to the period of extended operation.	LRA
7	The PWR Vessel Internals is a new program that manages the aging effects of various forms of cracking, including stress-corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress-corrosion cracking (IASCC), or cracking due to fatigue/cyclical loading; loss of material due to wear; loss of fracture toughness due to neutron irradiation embrittlement; changes in dimension due to void swelling and irradiation growth; and loss of preload due to thermal and irradiation-enhanced stress relaxation or creep. Program examination methods include visual examination, enhanced visual examination, volumetric examination, and direct physical measurements.	A.2.1.7	Program to be implemented no later than the date that the renewed operating licenses are issued.	LRA
8	The Flow-Accelerated Corrosion aging management program is an existing program that will be enhanced to: 1. Revise program procedures to require the documentation of the validation and verification of updated vendor supplied Flow-Accelerated Corrosion Program software which calculates component wear, wear rates, remaining life, and next scheduled inspection. The validation and verification will verify that the updated software performs these calculations consistently with NSAC-202L-R3 guidelines.	A.2.1.8	Program to be enhanced no later than six months prior to the period of extended operation.	LRA Exelon letter RS-14-143 5/15/ 2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
9	Bolting Integrity is an existing program that will be enhanced to: 1. Prohibit the use of lubricants containing molybdenum disulfide on pressure retaining bolted joints. 2. Prohibit the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for pressure retaining bolted joints in portions of systems within the scope of the Bolting Integrity program. 3. Perform visual inspection of submerged bolting on fire protection system pumps (Byron only) (Note 1) and well water system deep well pumps (Byron only) (Note 2) when submerged portions of the pumps are overhauled or replaced during maintenance activities.	A.2.1.9	Program to be enhanced no later than six months prior to the period of extended operation.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
10	Steam Generators is an existing program that will be enhanced to: 1. Validate that PWSCC of the divider plate welds to the primary head and tubesheet cladding is not occurring. BBS commits to perform one (1) of the following three (3) resolution options for Units 1 and 2: <u>Option 1: Inspection</u> Perform a one-time inspection, under the Steam Generators program, of each steam generator to assess the condition of the divider plate welds and the effectiveness of the Water Chemistry (A.2.1.2) program. For the Byron and Braidwood, Unit 1 steam generators which were replaced in 1998, the inspection will be performed between 2018 and either no later than 6 months prior to the start of the period of extended operation or the end of the last refueling outage prior to the period of extended operation, whichever occurs later, to allow the steam generators to acquire at least 20 years of service. For the Byron and Braidwood, Unit 2 steam generators which currently have at least 20 years of service, the inspection will be performed prior to entering the period of extended operation. The examination technique(s) will be capable of detecting PWSCC in the divider plate assemblies and associated welds. Or <u>Option 2: Analysis</u> Perform an analytical evaluation of the steam generator divider plate welds in order to establish a technical basis which concludes that the steam generator RCPB is adequately maintained with the presence of steam generator divider plate weld cracking. The analytical evaluation will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation.	A.2.1.10	Program to be enhanced no later than 6 months prior to the period of extended operation. Schedule for inspection and analysis activities identified in Commitment.	LRA Exelon Letter RS-14-052 03/04/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
10 (cont.)	Or <u>Option 3: Industry/NRC Studies</u> If results of industry and NRC studies and operating experience (OE) document that potential failure of the steam generator RCPB due to PWSCC of the steam generator divider plate welds is not a credible concern, this commitment will be revised to reflect that conclusion. 2. Validate that PWSCC of the tube-to-tubesheet welds is not occurring on BBS Unit 1. BBS commit to perform one (1) of the following three (3) resolution options for Unit 1: <u>Option 1: Inspection</u> Perform a one-time inspection, under the Steam Generators (A.2.1.10) program, of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. Since the Byron and Braidwood Unit 1 steam generators were replaced in 1998, the inspection will be performed between 2018 and either no later than 6 months prior to the start of the period of extended operation or the end of the last refueling outage prior to the period of extended operation, whichever occurs later, to allow the steam generators to acquire at least 20 years of service. The examination technique(s) will be capable of detecting PWSCC in the tube-to-tubesheet welds. If cracking is identified, the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
10 (cont.)	Or <u>Option 2: Analysis - Susceptibility</u> Perform an analytical evaluation of the steam generator tube-to-tubesheet welds to determine that the welds are not susceptible to PWSCC. The evaluation for determining that the tube-to-tubesheet welds are not susceptible to PWSCC will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation. Or <u>Option 3: Analysis – Pressure Boundary</u> Perform an analytical evaluation of the steam generator tube-to-tubesheet welds redefining the RCPB of the tubes, where the steam generator tube-to-tubesheet welds are not required to perform an RCPB function. The redefinition of the RCPB will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
11	Open-Cycle Cooling Water System is an existing program that will be enhanced to: 1. Perform periodic volumetric inspections for loss of material in the non-essential service water system piping at a minimum of two (2) locations on each unit in both the auxiliary building and the turbine building for a total of four (4) periodic inspections per unit every refueling cycle. 2. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide (RG) 1.54. 3. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program (CAP). 4. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM international standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). 5. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component. 6. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.	A.2.1.11	Program to be enhanced no later than six months prior to the period of extended operation.	LRA Exelon letter RS-14-124 05/05/2014 Exelon letter RS-14-175 06/30/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
12	Closed Treated Water Systems is an existing program that will be enhanced to: 1. Perform condition monitoring, including periodic visual inspections and NDEs, to verify the effectiveness of water chemistry control at mitigating aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, fouling, or cracking and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical. 2. Perform periodic sampling, analysis, and trending of water chemistry for the essential service water makeup pump engine glycol-based jacket water system to verify the effectiveness of water chemistry control at mitigating aging effects (Byron only) (Note 2).	A.2.1.12	Program to be enhanced no later than six months prior to the period of extended operation.	LRA
13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to: 1. Consistently include inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for evidence of loss of preload. 2. Ensure periodic inspections are performed on all cranes, hoists, monorails, and rigging beams within the scope of license renewal, including those that are infrequently in use.	A.2.1.13	Program to be enhanced no later than six months prior to the period of extended operation.	LRA
14	Compressed Air Monitoring is an existing program that will be enhanced to: 1. Inspect critical component internal surfaces for signs of loss of material due to corrosion and document deficiencies in the CAP.	A.2.1.14	Program to be enhanced no later than six months prior to the period of extended operation.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
15	Fire Protection is an existing program that will be enhanced to: 1. Include visual inspections of the earthen berm enclosing the outdoor fuel oil storage tanks for signs of age-related degradation such as loss of material and loss of form that could affect the intended function of the berm. 2. Provide additional inspection guidance to identify age-related degradation of fire barrier walls, ceilings, and floors or aging effects such as cracking, spalling, and loss of material. 3. Include visual inspection of halon and low-pressure carbon dioxide fire suppression system piping and component external surfaces for signs of corrosion or other age-related degradation.	A.2.1.15	Program to be enhanced no later than six months prior to the period of extended operation.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
16	Fire Water System is an existing program that will be enhanced to: 1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of National Fire Protection Association (NFPA) 25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2002 Edition), Section 5.3.1.1.1. This testing will be performed at the 50-year inservice date and every 10 years thereafter. 2. Provide for chemical addition accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion (Byron only) (Note 3). 3. Perform main drain testing annually, in accordance with NFPA 25, “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems,” Section 13.2.5. 4. Perform air flow testing of deluge systems that are not subject to periodic full flow testing on a three (3) year frequency to verify that internal flow blockage is not occurring (Byron only) (Note 1). 5. Perform inspections of Fire Protection System strainers when the system is reset after automatic actuation for signs of internal flow blockage (e.g., buildup of corrosion particles) (Braidwood only) (Note 1). 6. Increase the frequency of visual inspections of the internal surface of the foam concentrate tanks to at least once every ten (10) years. At least one (1) inspection will be performed within the ten (10) year period prior to entry into the period of extended operation, with subsequent inspections performed every ten (10) years thereafter.	A.2.1.16	Program to be enhanced no later than six months prior to the period of extended operation. Pre–period of extended operation activities specified in Enhancements 6 and 8 will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-078 03/13/2014 Exelon letter RS-14-169 06/16/2014 Exelon letter RS-14-175 06/30/2014 Exelon letter RS-14-235 08/29/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
16 (cont.)	7. Perform radiographic testing or internal visual inspections every five (5) years at the end of one (1) fire main and the end of one (1) sprinkler system branch line in half of the wet pipe sprinkler system within the scope of license renewal. If internal flow blockage that could result in failure of the system to deliver the required flow is identified, then perform an obstruction investigation. 8. Perform augmented testing beyond that specified in NFPA 25 on those portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect. The augmented testing will include: (1) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (2) volumetric wall-thickness examinations. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5)-year frequency thereafter. 9. Perform a minimum of 30 volumetric examinations of Fire Protection System piping, using radiographic testing or UT, during each three year interval. If volumetric examinations over a 10-year interval do not identify three (3) or more areas exhibiting reduction in wall thickness greater than 50 percent, then this minimum sample size is no longer required. (Byron only) (Note 3). 10. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54. 11. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the CAP.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
16 (cont.)	12. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). 13. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component. 14. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized. 15. Perform a minimum of 25 volumetric examinations of Fire Protection System piping, using radiographic testing or UT, during each 10-year interval.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
17	Aboveground Metallic Tanks is a new program that manages aging effects of loss of material and cracking on the external surfaces of aboveground metallic tanks within the scope of license renewal by performing periodic visual inspections once per eighteen (18) month operating cycle for degradation of the external surface of the insulation lagging, flashing, roof, and accessible sealant. The program also requires periodic visual inspections and liquid penetrant examinations of the tank external surfaces at 25 locations for both tanks combined per site and includes, on a sampling basis, removal of selected tank lagging and insulation to permit inspections of the external tank surfaces and exposed sealants. The tank external surface inspections and examinations will be performed each 10-year period starting 10 years prior to the period of extended operation. The sample locations will include at least four locations below penetrations through the insulation and its jacketing (e.g., instrument nozzles, tank heaters, ladder). The remaining sample locations will be distributed such that inspections will occur on the tank dome, sides, and near the bottom. One-time tank bottom ultrasonic inspections (one CST per station) will be performed within the 5-year period prior to the period of extended operation. The cathodic protection availability and effectiveness criteria in LR-ISG-2011-03 Table 4c, notes 3.ii and 3.iii, respectively, will be required to be met commencing 5 years prior to the period of extended operation and during the period of extended operation.	A.2.1.17	Program to be implemented no later than 6 months prior to the period of extended operation. The pre–period of extended operation inspection activities specified in the commitment will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-003 1/13/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
18	Fuel Oil Chemistry is an existing program that will be enhanced to: 1. Provide for the periodic cleaning of the Fire Protection Fuel Oil Storage Tank (Byron only) (Note 1). 2. Provide for periodic draining of water from the auxiliary feedwater (AFW) day tanks, diesel generator (DG) day tanks, essential Service Water make/up pump fuel oil storage tanks (Byron only) (Note 2), and Fire Protection Fuel Oil Storage Tanks. 3. Include analysis for the levels of microbiological organisms in the AFW day tanks and essential Service Water make-up pumps diesel oil storage tanks (Byron only) (Note 2). 4. Include analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms for the DG Day Tanks. 5. Include analysis for water and sediment content and the levels of microbiological organisms for the DG Fuel Oil Storage Tanks. 6. Include analysis for particulate concentration and the levels of microbiological organisms for the Fire Protection Fuel Oil Storage Tanks. 7. Include internal inspections of the Fire Protection Fuel Oil Storage Tanks at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected. 8. Include monitoring and trending for the levels of microbiological organisms for the AFW day tanks and essential Service Water make-up pumps diesel oil storage tanks (Byron only) (Note 2).	A.2.1.18	Program to be enhanced no later than 6 months prior to the period of extended operation. Pre–period of extended operation inspections specified in Enhancement 7 will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-124 05/05/2014 Exelon letter RS-14-175 06/30/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
18 (cont.)	9. Include monitoring and trending for water and sediment content, particulate concentration, and the levels of microbiological organisms for the DG Day Tanks. 10. Include monitoring and trending for water and sediment content and the levels of microbiological organisms for the DG Fuel Oil Storage Tanks. 11. Include monitoring and trending for total particulate concentration and the levels of microbiological organisms for the Fire Protection Fuel Oil Storage Tanks. 12. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in RG 1.54. 13. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the CAP. 14. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). 15. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component. 16. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.			

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19	Reactor Vessel Surveillance is an existing program that will be enhanced to: 1. Establish operating restrictions to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. The operating restrictions are as follows: Byron Station, Unit 1: - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum). - RPV beltline material fluence: 3.21E+19 n/cm^2 (E >1.0 MeV) (maximum). Byron Station, Unit 2; Braidwood Station Unit 1: - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum). - RPV beltline material fluence: 3.19E+19 n/cm^2 (E>1.0 MeV) (maximum). Braidwood Station, Unit 2: - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum). - RPV beltline material fluence: 3.16E+19 n/cm^2 (E>1.0 MeV) (maximum). If the reactor pressure vessel exposure conditions (neutron fluence, neutron spectrum) or irradiation temperature (cold leg inlet temperature) are altered, then the basis for the projection to the end of the period of extended operation needs to be reviewed and, if deemed appropriate, updates are made to the Reactor Vessel Surveillance program. Any changes to the Reactor Vessel Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.	A.2.1.19	Program to be enhanced no later than six months prior to the period of extended operation. Specimen capsule testing to be performed in accordance with the schedule described in Enhancement 2.	LRA Exelon Letter RS-14-002 01/13/2014 Exelon Letter RS-14-149 05/23/2014 Exelon Letter RS-14-225 07/28/2014

<table>
<tr><th>Item Number</th><th>Commitment</th><th>UFSAR Supplement Section or LRA Section</th><th>Implementation Schedule</th><th>Source</th></tr>
<tr><td>19
(cont.)</td><td>2. One (1) specimen capsule per reactor vessel, as designated below, irradiated to a neutron fluence of one (1) to two (2) times the projected peak neutron fluence at the end of the period of extended operation will be withdrawn from the spent fuel pool (SFP), tested, and the summary technical report submitted to the NRC within one (1) year of receipt of the renewed license. Alternatively, if a request for extension of the testing schedule is submitted in accordance with 10 CFR Part 50, Appendix H and granted by the Director, Office of Nuclear Reactor Regulation, specimen testing will be performed in accordance with that approved extension.
<table>
<tr><td>Reactor Vessel
(Station, Unit)</td><td>Capsule ID</td><td>Capsule Fluence
(n/cm^2)
(E>1.0 MeV)</td></tr>
<tr><td>Byron, Unit 1</td><td>Y</td><td>3.97E+19</td></tr>
<tr><td>Byron, Unit 2</td><td>Y</td><td>4.19E+19</td></tr>
<tr><td>Braidwood, Unit 1</td><td>V</td><td>3.71E+19</td></tr>
<tr><td>Braidwood, Unit 2</td><td>V</td><td>3.73E+19</td></tr>
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Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
20	One-Time Inspection is a new program that will be used to verify the system-wide effectiveness of the Water Chemistry, Fuel Oil Chemistry and Lubricating Oil Analysis programs. The One-Time Inspection AMP will also be utilized, in specific cases where existing data is insufficient: a. to validate that a particular aging effect is not occurring, or b. to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation. In these cases, the components will not require additional aging management.	A.2.1.20	Program to be implemented no later than 6 months prior to the period of extended operation. One-time inspections will be performed within the 10-year period prior to the period of extended operation, and will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-003 1/13/2014
21	Selective Leaching is a new program that will include one-time inspections of a representative sample of susceptible components to determine if loss of material due to selective leaching is occurring.	A.2.1.21	Program to be implemented no later than 6 months prior to the period of extended operation. One-time inspections will be performed within the five (5)-year period prior to the period of extended operation, and will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
22	One-Time Inspection of ASME Code Class 1 Small-Bore Piping is a new program that will manage the aging effect of cracking in Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch. The socket weld sample population for Byron Unit 1 will include the socket weld on the “D” safety injection system cold leg injection line that was replaced in 1998.	A.2.1.22	Program to be implemented no later than 6 months prior to the period of extended operation. One-time Inspections will be performed and evaluated within the six (6)-year period prior to the period of extended operation, and will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon Letter RS-14-002 01/13/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
23	External Surfaces Monitoring of Mechanical Components is a new program that manages aging effects of metallic and elastomeric materials through periodic visual inspection of external surfaces for evidence of loss of material and cracking. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation. Periodic representative inspections to detect corrosion (i.e., loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic visual inspections under insulation to detect corrosion and cracking under insulation will continue.	A.2.1.23	Program to be implemented no later than six months prior to the period of extended operation.	LRA Exelon letter RS-14-003 1/13/2014 Exelon letter RS-14-051 2/27/2014 Exelon letter RS-14-218 07/18/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
24	Flux Thimble Tube Inspection is an existing program that will be enhanced as follows: 1. For Braidwood Units 1 and 2 (Note 3): Perform corrective actions to re-establish periodic eddy current testing of the flux thimble tubes prior to the period of extended operation to ensure that wall thickness is monitored to detect loss of material from the flux thimble tubes. Once periodic eddy current testing is reestablished, eddy current testing will be performed for each flux thimble tube every refueling outage until sufficient data has been accumulated to establish a plant-specific eddy current testing frequency to ensure that no flux thimble tube is predicted to incur wear that exceeds 80% before the next inspection. Flux thimble tube wall thickness measurements will be trended and wear rates will be calculated based on plant-specific data. Wall thickness will be projected using plant-specific data in accordance with the WCAP-12866, “Bottom Mounted Instrumentation Flux Thimble Wear,” methodology. 2. For Braidwood Unit 1 (Note 3): a. The 17 Braidwood Station, Unit 1 flux thimble tubes that exhibited indications of wear during eddy current testing performed during Refueling Outage A1R15 (Fall 2010), will be replaced or removed from service during Refueling Outage A1R18 (Spring 2015), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. (Flux thimble tubes 1 (J-8), 8 (K-6), 9 (H-11), 12 (E-9), 14 (H-4), 18 (L-11), 19 (L-5), 21 (E-11), 23 (D-10), 36 (J-14), 37 (P-9), 41 (N-4), 44 (R-8), 45 (N-13), 48 (P-4), 54 (A-11), 55 (N-14)) b. The remaining Braidwood Station, Unit 1 flux thimble tubes, not replaced during A1R18, will be replaced or removed from service during Refueling Outage A1R19 (Fall 2016), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. c. Following A1R19, any Braidwood Station, Unit 1 flux thimble tube will be replaced every two (2) refueling	A.2.1.24	Byron: Ongoing Braidwood: Schedule for flux thimble tube replacement activities identified in commitment. Corrective actions to reestablish periodic eddy current testing at Braidwood will be completed either no later than six months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later. Braidwood Unit 1: Commitment 2.a was completed during refueling outage A1R18 in Spring 2015.	LRA Exelon letter RS-14-336 11/22/2014 Exelon letter RS-15-071 02/23/15 Exelon letter RS-15-107 04/13/2015

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
	outages or removed from service if eddy current data is not obtained in accordance with the Flux Thimble Tube Inspection program. 3. For Braidwood Unit 2 (Note 3): a. The 29 Braidwood Station, Unit 2 flux thimble tubes that exhibited indications of wear during eddy current testing performed during A2R15 Refueling Outage (Spring 2011) and not replaced during A2R17 Refueling Outage (Spring 2014), will be replaced or removed from service during A2R18 Refueling Outage (Fall 2015), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. (Flux thimble tubes 1 (J-8), 4 (H-6), 5 (F-8), 6 (J-10), 7 (F-7), 9 (H-11), 10 (L-8), 11 (G-5), 18 (L-11), 22 (K-12), 23 (D-10), 24 (H-13), 25 (N-8), 26 (H-3), 27 (C-8), 29 (N-6), 32 (L-13), 33 (C-5), 34 (H-2), 36 (J-14), 37 (P-9), 40 (F-14), 41 (N-4), 42 (D-3), 45 (N-13), 46 (J-1), 50 (R-6), 52 (L-15), 56 (N-2)) b. The remaining Braidwood Station, Unit 2 flux thimble tubes, not replaced during A2R17 or A2R18, will be replaced or removed from service during A2R19 Refueling Outage (Spring 2017), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. c. Following A2R19, any Braidwood Station, Unit 2 flux thimble tube will be replaced every two (2) refueling outages or removed from service if eddy current data is not obtained in accordance with the Flux Thimble Tube Inspection program.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is a new program that manages aging effects of metallic and elastomeric materials through visual inspections of internal surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement.	A.2.1.25	Program to be implemented no later than six months prior to the period of extended operation.	LRA Exelon letter RS-14-003 1/13/2014
26	Existing Lubricating Oil Analysis program is credited.	A.2.1.26	Ongoing	LRA
27	Monitoring of Neutron-Absorbing Materials Other than Boraflex is an existing program that will be enhanced to: 1. Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks prior to coupons being examined, by ensuring that the coupons have been surrounded with a greater number of freshly discharged fuel assemblies than that of any other cell location.	A.2.1.27	Program to be enhanced no later than six months prior to the period of extended operation.	LRA Exelon letter RS-14-052 03/04/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
28	Buried and Underground Piping is an existing program that will be enhanced to: 1. Perform manual examinations, in addition to visual inspections, to detect hardening, softening, or other changes in material properties for buried polymeric piping (Braidwood only) (Note 2). 2. Cracking will be managed for stainless steel components, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed and expose the base material (Braidwood only) (Note 2). 3. Ensure all underground carbon steel essential service water system piping within the scope of license renewal is coated in accordance with National Association of Corrosion Engineers (NACE) SP0169-2007 prior to the period of extended operation (Byron only) (Note 1). 4. Direct visual inspections of coated piping and components will be performed by an individual possessing a NACE Coating Inspector Program Level 2 or 3 operator qualification, or by an individual who has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course. 5. Inspection quantities of buried piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based upon the as-found results of cathodic protection system availability and effectiveness during each ten year period, beginning 10 years prior to the period of extended operation.	A.2.1.28	Program to be enhanced no later than 6 months prior to the period of extended operation. Pre–period of extended operation activities specified in Enhancements 3, 5, 6, and 7 will be completed either no later than 6 months prior to the period of extended operation, or before the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-003 1/13/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
28 (cont.)	6. The buried carbon steel condensate system piping within the scope of license renewal will be addressed, through means of a long term mitigation strategy, prior to entering the period of extended operation. Mitigation may include activities such as fully recoating, complete replacement with like or upgraded material, installation of internal polymeric sleeves, and routing of pipe above ground or in an engineered trench for leak detection. Inspections of the condensate system piping will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based on the mitigation strategy implemented (Braidwood only) (Note 3). 7. Inspection quantities of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10 year period, beginning 10 years prior to the period of extended operation. a. The piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications (Byron only) (Note 3). 8. If adverse indications are detected during inspection, inspection sample sizes within the affected piping categories will be doubled. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the analysis. Timing of the additional inspections will be based on the severity of the identified degradation and the consequences of leakage. In all cases, the additional inspections will be performed within the same 10-year inspection interval in which the original adverse indication was identified. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism.			

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28 (cont.)	9. In performing cathodic protection surveys, only the −850 mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness. Alternatively, soil corrosion, or electrical resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys. An upper limit of −1200 mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings. 10. An extent of condition evaluation will be conducted if observed coating damage caused by non-conforming backfill has been evaluated as significant. The extent of condition evaluation will be conducted to ensure that the as-left condition of backfill in the vicinity of the observed damage will not lead to further degradation.			
29	ASME Section XI, Subsection IWE is an existing program that will be enhanced to: 1. Provide guidance for specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. 2. Use the condition of the embedded reinforcing steel at the inner surface of the tendon tunnel as a representative indicator for the potential for corrosion at the exterior surface of the containment liner plate. Use the results of Structures Monitoring (B.2.1.34) AMP, Enhancement 16 activities and results from ongoing examinations of the tendon tunnel performed as part of the ASME Section XI, Subsection IWL (B.2.1.30) and Structures Monitoring (B.2.1.34) AMPs to identify changing conditions. Changing conditions consisting of the identification of significant corrosion of embedded steel in the tendon tunnel structure require an evaluation to determine if augmented examinations in accordance with requirements of IWE-1240 “Surface Areas Requiring Augmented Examination” are required due to the potential for accelerated corrosion at the exterior surface of the containment liner plate.	A.2.1.29	Program to be enhanced no later than six months prior to the period of extended operation.	LRA Exelon Letter RS-14-183 7/8/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
30	ASME Section XI, Subsection IWL is an existing program that will be enhanced to: 1. Include additional augmented examination requirements after post-tensioning system repair/replacement activities in accordance with Table IWL-2521-2. 2. A one-time inspection of one (1) vertical and one (1) horizontal tendon on each unit will be performed prior to the period of extended operation. The inspection will consist of visually examining one (1) wire from each of the two (2) types of tendons at a worst-case location based on evidence of free water, grease discoloration, and grease chemistry results. This location will serve as a leading indicator for potential degradation or tendon surface corrosion. The visual inspection of these wires will be performed in accordance with existing station procedures used for inspections consistent with IWL-2523.2. The acceptance criteria will consist of each wire being free of any active corrosion, including general and pitting corrosion. In the event that the acceptance criteria are not met and corrosion is identified, the condition will be entered into the CAP. The condition will be evaluated to characterize the corrosion, determine the cause of the corrosion, the location, depth, extent of the condition, and applicability of the condition to other wires that comprise that tendon. Corrective actions may include activities such as grease analysis, replacement of grease within the tendon duct, additional wire inspections from the same tendon, evaluation of the tendon capacity, potential replacement of the tendon, and augmented inspections and grease sampling of other leading indicator tendons, based, in part, on previous evidence of free water, observed grease leakage, grease discoloration, and grease chemistry results. Specific corrective actions will depend upon the cause, extent of condition, and grease properties. These corrective actions will be consistent with those actions which would be evaluated during periodic required IWL examinations (Braidwood only) (Note 3).	A.2.1.30	Program to be enhanced no later than 6 months prior to the period of extended operation. Pre–period of extended operation inspections specified in Enhancements 2 and 3 will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon Letter RS-14-183 7/8/2014 Exelon Letter RS-14-328 11/21/2014 Exelon Letter RS-14-216 12/15/2014

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30 (cont.)	3. In order to monitor for tendon exposure to free water and moisture and manage any potential adverse effects, a periodic tendon water monitoring and grease sampling program will be implemented (Braidwood only) (Note 3). The program will consist of: a. A baseline inspection of tendon grease caps at the bottom of all vertical and dome tendons, as well as all below-grade horizontal tendons, prior to the period of extended operation. The baseline inspection will check for evidence of free water and grease discoloration, with further actions taken based on the condition of the grease. b. A followup tendon grease cap inspection of all vertical and dome tendons, as well as all below-grade horizontal tendons, will be performed within 10 years of the initial inspection, using the same approach as the baseline inspection.			

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30 (cont.)	c. For those tendons where free water, moisture, and grease did not meet acceptance criteria during the two (2) previous inspections, periodic monitoring of grease chemistry and moisture, free water, and grease discoloration will be performed on a frequency not to exceed 10 years. Tendons, which exhibit significant quantities of free water (e.g., more than eight ounces) during periodic monitoring, will be inspected more often, with the timing of followup inspections increased until a frequency is achieved that no longer results in significant amounts of free water observed during successive inspections. Tendon water inspection and draining frequencies may vary from annual to every ten (10) years, depending upon grease chemistry and moisture parameters meeting IWL acceptance criteria. The maximum ten (10) year periodic frequency is meant to address any tendons which exhibit evidence of free water but the quantity is observed to be insignificant, with no observable grease discoloration, and given that the tendon was not inspected for at least ten (10) years prior. More frequent followup inspections will be performed for tendons which exhibit insignificant quantities of free water, but were inspected within the ten (10) years prior. In all cases, the frequency of inspections for water in individual tendons will be adjusted to be commensurate with the severity of the conditions found during each examination.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
30 (cont.)	d. Braidwood has performed augmented inspections on additional tendons beyond those selected for the ASME Section XI, Subsection IWL program. The Braidwood augmented inspections are performed on a 5 year frequency, in conjunction with the ASME Section XI, Subsection IWL AMP. The current augmented examinations of additional tendons will continue until the periodic tendon water monitoring and grease sampling program described above is implemented. Corrective actions will be taken as necessary to ensure that the tendon grease meets ASME Section XI, Subsection IWL requirements. 4. Explicitly require that areas of concrete deterioration and distress be recorded in accordance with the guidance provided in American Concrete Institute (ACI) 349.3R. The visual resolution capability of direct and remote examination techniques will be sufficient to detect concrete degradation at the levels described in Chapter 5 of ACI 349.3R. The resolution capability of the optical aids used for remote examinations will be demonstrated as equivalent to direct visual examination. 5. Include quantitative acceptance criteria, based on the “Evaluation Criteria” provided in Chapter 5 of ACI 349.3R, that will be used to augment the qualitative assessment of the Responsible Engineer. In addition, the Responsible Engineer will confirm that the visual resolution capability used for the concrete containment structure examinations was sufficient to evaluate the examination results against the quantitative acceptance criteria described in Chapter 5 of ACI 349.3R.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
31	ASME Section XI, Subsection IWF is an existing program that will be enhanced to: 1. Add the MC supports for the transfer tube in the refueling cavity in the containment structure and refueling canal in the fuel handling building to the scope of the program. 2. Revise implementing documents to provide guidance for proper specification of bolting material, storage, lubricants and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Bolting material with actual measured yield strength of 150 ksi or greater shall not be used in plant changes without engineering approval, due to consideration of SCC vulnerability. Storage requirements for high strength bolts shall include the recommendations of the Research Council on Structural Connections, “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” Section 2. Lubricants that contain MoS_2 shall not be applied to high strength structural bolts within the scope of license renewal. 3. Provide procedural guidance, regarding the selection of supports to be inspected on subsequent inspections, when a support is repaired in accordance with the CAP. The enhanced guidance will ensure that the supports inspected on subsequent inspections are representative of the general population.	A.2.1.31	Program to be enhanced no later than 6 months prior to the period of extended operation. Pre–period of extended operation examinations specified in Enhancements 4 and 5 will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon Letter RS-14-052 03/04/2014 Exelon Letter RS-14-170 06/16/2014 Exelon Letter RS-14-235 08/29/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
31 (cont.)	4. Perform one-time volumetric examinations on a sample of ASTM A490 bolts, greater than 1-in. nominal diameter for the detection of SCC prior to the period of extended operation. Volumetric examinations will be performed in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. The sample will consist of bounding and representative A490 bolt sizes, joint configurations, and environmental exposure conditions. The sample will consist of 20% of the ASTM A490 bolts greater than 1-in. nominal diameter or a maximum of 25 ASTM A490 bolts total for both Byron and Braidwood stations. The selection of the samples will consider susceptibility to SCC (e.g., actual measured yield strength) and ALARA principles. Any adverse results of the volumetric examinations will be entered into the CAP and will be evaluated by engineering to determine if additional actions are warranted such as expansion of sample size, scope, and frequency of any additional supplemental visual or volumetric examinations, as well as any code requirements specified by ASME Section XI, Subsection IWF. Specifically, the implementing documents for performing the one-time volumetric examinations will have criteria for extending the ASTM A490 bolt examination scope to other ASTM A490 bolts used in similar joint configurations and environmental exposure conditions if the volumetric examination of a bolt shows adverse results, which is similar to the methodology used by the ASME Code IWF-2430 for IWF component supports. In addition, the program will be revised to include periodic volumetric examinations, of ASTM A490 bolts in sizes greater than 1-in. nominal diameter, if the one-time volumetric examination of an ASTM A490 bolt shows signs of cracking. The periodic examinations of the ASTM A490 bolts are included in the periodic examination of the supports. For the periodic examinations of supports, the population of the supports examined is specified in Table IWF-2500-1. Consistent with the GALL Report, the periodic examinations will include volumetric examinations of high-strength bolts to detect cracking, if required, in addition to			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
31 (cont.)	4. (continued) the VT-3 examinations of the high-strength bolts. 5. Revise implementing documents to perform periodic visual examinations to detect a corrosive environment that supports SCC potential for all (100%) of high strength bolting greater than 1-in. nominal diameter prior to the period of extended operation, and then each inspection interval of 10 years thereafter. The periodic visual examinations will include criteria to identify if the bolting has been exposed to moisture or other contaminants by evidence of moisture, residue, foreign substance, or corrosion. Adverse conditions identified during the examinations will be evaluated by engineering to determine if the bolt has been exposed to a corrosive environment with the potential to cause SCC. The bolts determined to have been exposed to corrosive environment with the potential to cause SCC will be included in a sample population for each specific bolt material where SCC is a concern. A sample size equal to 20 percent (rounded up to the nearest whole number) of the bolts in the sample population, with a maximum sample size of 25 bolts will be subject to supplemental volumetric examination to determine if SCC is present. The selection of the samples will consider susceptibility to SCC (e.g., actual measured yield strength) and ALARA principles. Volumetric examinations will be performed in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. The results of the volumetric examinations will be evaluated by engineering to determine if additional actions are warranted such as expansion of sample size, scope, and frequency of any additional supplemental visual or volumetric examinations, as well as any code requirements specified by ASME Section XI, Subsection IWF. 6. Add the CRDM seismic support assembly to the scope of the program to implement additional examinations.			
32	Existing 10 CFR Part 50, Appendix J program is credited.	A.2.1.32	Ongoing	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
33	Masonry Walls is an existing program that will be enhanced to: 1. Add masonry walls in the following structures to the program scope: a. Radwaste and Service Building Complex i. Radwaste Building ii. Original Service Building b. Turbine Building Complex c. Switchyard Structures i. Relay House 2. Provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and the masonry walls that could impact the intended function of the masonry walls. 3. Require that personnel performing inspections and evaluations meet the qualifications described in ACI 349.3R.	A.2.1.33	Program to be enhanced no later than six months prior to the period of extended operation.	LRA
34	Structures Monitoring is an existing program that will be enhanced to: 1. Add the following structures: a. Radwaste and Service Building Complex i. Radwaste Building ii. Original Service Building b. Turbine Building Complex c. Yard Structures i. Transformer foundations ii. Valve and line enclosures d. Fire protection structures-features i. Transformer fire barrier walls ii. Fuel oil storage tank berm e. Containment structure features i. Containment access facility hallway	A.2.1.34	Program to be enhanced no later than 6 months prior to the period of extended operation. Pre–period of extended operation activities specified in Enhancement 16 will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon Letter RS-13-274 12/19/2013 Exelon letter RS-14-097 04/17/2014 Exelon letter RS-14-169 06/16/2014 Exelon Letter RS-14-216 12/15/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
34 (cont.)	2. Add the following components and commodities: a. Blowout panels b. Building features – doors and seals, bird screens, louvers, windows c. Compressible joints and seals, gaskets and moisture barriers d. Concrete curbs e. Electrical cable trays, conduits and tube tracks f. Hatches and plugs g. Insulation including jacketing h. Manholes, handholes and duct banks i. Metal components, including metal decking for concrete slabs, miscellaneous steel, sump screens and trench covers, and scuppers around the SFP j. New fuel storage racks k. Offgas stack and flue l. Panels, racks, cabinets, and other enclosures m. Penetration seals and sleeves n. Pipe whip restraints, jet impingement shields, and spray shields o. Pipe, electrical and equipment component support members p. Sliding surfaces q. SFP gates r. Sumps and liners 3. Monitor groundwater chemistry on a frequency not to exceed five (5) years for pH, chlorides, and sulfates and evaluate results exceeding the threshold criteria to assess impact, if any, on below-grade concrete. 4. Based on groundwater chemistry monitoring results, select and inspect every five (5) years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
34 (cont.)	5. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason. 6. Provide guidance for proper specification of high strength bolting material and lubricant to prevent or mitigate degradation and failure of structural bolting. 7. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0. 8. Clarify that loose bolts and nuts, and cracked high strength bolts are not acceptable unless accepted by engineering evaluations. 9. Include the potential for reduction in concrete anchor capacity due to local concrete degradation. 10. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R with respect to knowledge of inservice inspection of concrete and visual acuity requirements. 11. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R. 12. Perform inspection of elastomeric components such as vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric components are to be supplemented by feel or manipulation to detect hardening. 13. Monitor accessible sliding surfaces to detect loss of mechanical function or significant loss of material due to wear, corrosion, debris, dirt, distortion, or overload that could restrict or prevent sliding of surfaces as required by design.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
34 (cont.)	14. Formalize requirements for the monitoring of the leak detection sight glasses associated with the refuel cavity, transfer canal, SFP, and refueling water storage tank on a periodic basis. 15. Require visual inspections of submerged concrete structural elements by dewatering a structure or by a diver if the structure is not dewatered at least once every five (5) years (Byron only) (Note 2).			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
34 (cont.)	16. At each site, perform one-time sampling activities on below grade, reinforced concrete at specific locations in the tendon tunnels. Select the locations exhibiting significant mineral deposits to serve as leading indicators for potential reinforced concrete degradation as a result of exposure to ground water in-leakage and build-up of mineral deposits. Take corrective actions, if necessary, prior to the period of extended operation. Perform the one-time sampling activities as follows: a. Obtain water in-leakage samples, at representative locations with mineral deposits due to water in-leakage, and analyze for pH, chlorides, sulfates, minerals, and iron content. b. Obtain representative mineral deposit samples and analyze for chemical composition. c. Remove three concrete core samples. i. Test two of the concrete core samples for compressive strength and perform petrographic examination of the core samples. Select representative locations for the concrete core samples that include one with significant mineral deposits and another at a location with no mineral deposits for comparative purposes. ii. Drill an additional core at a crack with significant mineral deposits and subject the core to petrographic examination. d. Expose and examine reinforcing steel at two locations, with water in-leakage, cracks, and significant mineral deposits. e. Collectively evaluate the results from the water inleakage analysis, the chemical composition of the mineral deposits, examination of the exposed reinforcing steel, and the core sample testing to confirm there is no significant degradation to the reinforced concrete material properties and to determine if additional corrective actions are necessary. Additional corrective actions may include, but are not limited to, an extent of condition review for other potentially impacted structures, more frequent examinations, and additional sampling and analysis, as appropriate.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
34 (cont.)	17. Perform visual inspections of polymeric components, such as blowout panels, for changes in material properties. Observations of material discoloration, cracking, crazing, and loss of material will provide visual indications of changes in material properties prior to a loss of component intended function.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
35	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants is an existing program that will be enhanced to: 1. Provide guidance for specification of structural bolting material and bolting lubricants to prevent or mitigate degradation and failure of structural bolting. 2. Revise storage requirements for structural bolting to include recommendations of RCSC Specification for Structural Joints Using High Strength Bolts, Section 2.0. 3. Include the potential for reduction in concrete anchor capacity due to local concrete degradation. 4. Include all aging affects addressed by ACI 349.3R in procedures and require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R. 5. Clarify that loose bolts and nuts, and cracked bolts are not acceptable unless accepted by engineering evaluations. 6. Require that steel components subject to RG 1.127 are inspected for loss of material. 7. Require that inspectors work under the direction of a qualified engineer for submerged concrete inspections. 8. Require special inspections also be performed in the event of large floods, hurricanes, and intense local rainfalls. 9. Require increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection. 10. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason.	A.2.1.35	The Byron Essential Service Water Cooling Tower inspection and maintenance plan (Enhancement 16) will be initiated upon receipt of the renewed licenses, and will continue through the period of extended operation to ensure the condition of the SXCT is maintained. The remainder of the enhancements will be implemented no later than six months prior to the period of extended operation.	LRA Exelon Letter RS-14-216 12/15/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
35 (cont.)	11. Monitor raw water and groundwater chemistry at least once every five (5) years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete. 12. Based on groundwater chemistry monitoring results, select and inspect every five (5) years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater. 13. Require visual inspections of submerged concrete structural components by dewatering a structure or by a diver if the structure is not dewatered at least once every five (5) years. Maintenance procedures will be enhanced to require opportunistic inspection of submerged concrete structures when they are dewatered and made accessible. 14. Require that degraded conditions be documented and trended until the condition is no longer occurring or until a corrective action is implemented. 15. Clarify parameters to be monitored and inspected at the Essential Service Water Cooling Towers to include visual inspection for loss of material and reduction of heat transfer for the cooling tower fill, and visual inspection with physical manipulation for change in material properties associated with the PVC drift eliminators and fiberglass support beams for the drift eliminators (Byron only) (Note 2).			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
35 (cont.)	16. Manage the condition of the Byron Essential Service Water Cooling Towers (SXCTs) as follows: a. Monitor and trend inspection activities at the SXCTs on an increased frequency, with inspections of the entire tower on a three (3) year interval, and inspections of the fill support beams and air-inlet framing on a 1.5-year interval. The recommendations in Chapter 5 of ACI 349.3R will be used for quantitative acceptance and evaluation criteria. b. Develop a repair plan to address degradation of the SXCTs with specific emphasis and consideration for the fill support beams. Repairs that are required will be scheduled based on a ranking of the condition observed and the potential for the degradation to progress or propagate.			
36	Protective Coating Monitoring and Maintenance Program is an existing program that will be enhanced to: 1. Add recurring work orders requiring Service Level I coating inspections every refuel outage. 2. Require qualification of coating inspectors to ASTM D 5498. 3. Require qualification of personnel in accordance with ASTM D 7108. 4. Incorporate guidance for inspection and maintenance of Service Level I coatings per RG 1.54 and impose ASTM D 5163-08 requirements for Service Level I coatings condition assessment, reporting, evaluation, and documentation. 5. Require thorough visual inspections of all coatings near sumps or screens associated with the emergency core cooling system (ECCS) by the coatings inspector(s). 6. Specify instruments and equipment that may be needed for Service Level I coatings inspections.	A.2.1.36	Program to be enhanced no later than six months prior to the period of extended operation.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
37	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage aging of the insulation material for non-EQ cables and connections. Accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of reduced insulation resistance, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination.	A.2.1.37	Program to be implemented no later than 6 months prior to the period of extended operation. Initial inspections will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA
38	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is a new program that will be used to manage aging of non-EQ cable and connection insulation of the in-scope portions of the radiation monitoring system (Byron and Braidwood) and the neutron monitoring inputs to the reactor protection system (Braidwood only) (Note 2). Calibration and cable tests (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition) will be performed and results will be assessed for reduced insulation resistance prior to the period of extended operation and at least once every 10 years during the period of extended operation.	A.2.1.38	Program to be implemented no later than 6 months prior to the period of extended operation. Initial calibration, cable tests and evaluation of results will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-030 2/4/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
39	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope, inaccessible power cables. Cables will be tested using one or more proven tests for detecting reduced insulation resistance of the cable's insulation system. The cables will be tested at least once every 6 years. More frequent testing may occur based on test results and OE. Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this program will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific OE with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. Operation of dewatering devices, if installed, will be verified prior to any known or predicted heavy rain or flooding event. During the period of extended operation, the inspections will occur at least annually.	A.2.1.39	Program to be implemented no later than 6 months prior to the period of extended operation. First cable tests and manhole inspections will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA Exelon letter RS-14-041 2/19/2014
40	Metal Enclosed Bus is an existing program that will be enhanced to: 1. Specify that a sample size of 20 percent of the accessible bolted connection population with a maximum sample size of 25 to be inspected for increased resistance of connection by measuring the connection resistance using a micro-ohmmeter. 2. Specify that the external surfaces of metal enclosed bus enclosure assemblies are to be inspected for loss of material due to general, pitting, and crevice corrosion. 3. Specify maximum allowed bus connection resistance values.	A.2.1.40	Program to be enhanced no later than six months prior to the period of extended operation.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
41	Fuse Holders (Byron only) (Note 2) AMP is a new program that applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects. Fuse holders subject to increased resistance of connection or fatigue, will be tested, by a proven test methodology, at least once every 10 years for indications of aging degradation. Visual inspection is not part of this program.	A.2.1.41	Program to be implemented no later than 6 months prior to the period of extended operation. Initial resistance tests will be completed either no later than 6 months prior to period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA
42	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will implement one-time testing of a representative sample (20 percent with a maximum sample size of 25) of non-EQ electrical cable connections to ensure that either aging of metallic cable connections is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required.	A.2.1.42	Program to be implemented no later than 6 months prior to the period of extended operation. One-time tests will be completed either no later than 6 months prior to the period of extended operation, or before the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	LRA

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
43	Fatigue Monitoring is an existing program that will be enhanced to: 1. Address the cumulative fatigue damage effects of the reactor coolant environment on component life by evaluating the impact of the reactor coolant environment on critical components for the plant identified in NUREG/CR-6260. Additional plant-specific component locations in the RCPB will be evaluated if they are more limiting than those considered in NUREG/CR-6260. 2. Monitor and track additional plant transients that are significant contributors to component fatigue usage. 3. Evaluate the effects of the reactor coolant system water environment on the reactor vessel internal components with existing fatigue CUF analyses to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121. 4. Increase the scope of the program to include transients used in the analyses for ASME Code Section III fatigue exemptions, the allowable stress analyses associated with ASME Code Section III and ANSI B31.1, and the flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600.	A.3.1.1	Program to be enhanced no later than 6 months prior to the period of extended operation. Environmental fatigue evaluations will be completed no later than 6 months prior to the period of extended operation.	LRA Exelon letter RS-14-002 01/13/2014
44	Concrete Containment Tendon Prestress is an existing program that will be enhanced to: 1. For each surveillance interval, the predicted lower-limit, minimum required value, and trending lines will be developed for the period of extended operation as part of the regression analysis for each tendon group.	A.3.1.2	Program to be enhanced no later than six months prior to the period of extended operation.	LRA
45	The Environmental Qualification (EQ) of Electric Components AMP will be enhanced: 1. To expand the scope of the program to include mechanical environmental qualification (MEQ) components.	A.3.1.3	Program to be enhanced no later than six months prior to the period of extended operation.	LRA Exelon letter RS-14-079 3/04/2014

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
46	The Operating Experience Program is an existing program that will be enhanced to: 1. Require the review of internal and external OE for aging-related degradation or impacts to aging management activities, to determine if improvements to Byron and Braidwood Units 1 and 2 aging management activities are warranted. NRC and industry guidance documents and standards applicable to aging management are considered part of this information (e.g., License Renewal Interim Staff Guidance (LR-ISG) documents, NUREG-1801 (GALL) revisions, etc.) Ensure there are written expectations for identifying and processing these documents as OE. 2. Establish criteria to define aging-related degradation. In general, the criteria will be used to identify aging that is in excess of what would be expected, relative to design, previous inspection experience and the inspection intervals. 3. Establish identification coding within the CAP for use in identification, trending and communications of aging-related degradation. Provide a definition for the coding. This coding will assist plant personnel in ensuring that, in addition to addressing the specific issue, the adequacy of existing AMPs is assessed. Station personnel are required to periodically assess the performance of the AMPs, including insights obtained through OE. Adverse trends are entered into the CAP for evaluation. This could lead to AMP revisions or the establishment of new AMPs, as appropriate. 4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.	A.1.6	Program to be enhanced no later than the date that the renewed operating licenses are issued and conducted on an ongoing basis throughout the terms of the renewed licenses.	LRA
46 (cont.)	5. Provide training to those responsible for screening, evaluating and communicating OE items related to aging management and aging-related degradation. This training will be commensurate with their role in the process, will be provided periodically and include provisions to accommodate personnel turnover.			

Item Number	Commitment	UFSAR Supplement Section or LRA Section	Implementation Schedule	Source
47	Byron Unit 2 reactor head closure stud location 11 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation – reported complete by letter dated December 15, 2014 (Byron only. Note 3).		No later than six months prior to the period of extended operation.	Exelon letter RS-13-285 12/19/2013 Exelon Letter RS-14-216 12/15/2014
48	Braidwood Unit 2 reactor head closure stud location 35 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation (Braidwood only. Note 3).		No later than six months prior to the period of extended operation.	Exelon letter RS-13-285 12/19/2013 Exelon Letter RS-14-216 12/15/2014

APPENDIX B

CHRONOLOGY

This appendix contains a chronological listing of the routine correspondence between the staff of the U.S. Nuclear Regulatory Commission (the staff) and Exelon Generation Company, LLC (Exelon or the applicant), and other correspondence regarding the staff's reviews of the Byron Station, Units 1 and 2, and the Braidwood Station, Units 1 and 2, Docket Numbers 50-454, 50-455, 50-456, and 50-457, license renewal application (LRA).

Date	Subject
May 29, 2013	Braidwood and Byron, Units 1 and 2 - Application for Renewed Operating Licenses (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13155A387)
May 29, 2013	Braidwood and Byron, Units 1 and 2 - Information to Support NRC Staff Review of the Application for Renewed Operating Licenses (ADAMS Accession No. ML13155A388)
May 29, 2013	Braidwood License Renewal Boundary Drawings (ADAMS Accession No. ML13154A218)
May 29, 2013	Byron Station, Units 1 & 2, License Renewal Boundary Drawing (ADAMS Accession No. ML13154A227)
May 29, 2013	Byron and Braidwood, Units 1 and 2 - License Renewal Application, Volume 1 of 4 (ADAMS Accession No. ML13155A420)
May 29, 2013	Byron and Braidwood, Units 1 and 2 - License Renewal Application, Volume 2 of 4 (ADAMS Accession No. ML13155A421)
June 3, 2013	Byron and Braidwood, Units 1 and 2 - License Renewal Application (ADAMS Accession No. ML13161A223)
June 6, 2013	Letter to Gallagher M. P., Exelon Generation Company, LLC: Letter-Receipt and Availability of the License Renewal Application for the Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2 (ADAMS Accession No. ML13144A099)
July 16, 2013	Letter to Gallagher M. P., Exelon Generation Company, LLC: Determination Of Acceptability And Sufficiency For Docketing, Proposed Review Schedule, And Opportunity For A Hearing Regarding The Application From Exelon Generation Company, LLC, For Renewal Of The Operating Licenses For Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2 (ADAMS Accession No. ML13134A142)
August 12, 2013	Letter to Gallagher M. P., Exelon Generation Company, LLC: Plan for the Aging Management Program Regulatory Audits Regarding the Byron and Braidwood Nuclear Stations License Renewal Application Review (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML13212A367)
October 7, 2013	Letter to Gallagher M. P., Exelon Generation Company, LLC: Requests For Additional Information For The Review Of The Byron Nuclear Station, Units 1 And 2, And Braidwood Nuclear Station, Units 1 And 2, License Renewal Application -Aging Management, Set 1 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML13262A035)
October 28, 2013	Summary Of Telephone Conference Call Held On September 25, 2013 Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning RAIs Pertaining To The Byron-Braidwood License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML13281A557)
November 5, 2013	Braidwood Station, Units 1 & 2 and Byron Station, Units 1 & 2 - Response to NRC Requests for Additional Information, Set 1, dated October 7, 2013, re License Renewal Application (ADAMS Accession No. ML13309B590)
November 22, 2013	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 5 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML13310A576)

Date	Subject
November 25, 2013	Letter to Gallagher M. P., Exelon Generation Company, LLC: Requests For Additional Information For The Review Of The Byron Nuclear Station, Units 1 And 2, And Braidwood Nuclear Station, Units 1 And 2, License Renewal Application - Aging Management, Set 3 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML13281A574)
November 25, 2013	Summary Of Telephone Conference Call Held On October 22, 2013, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning RAI Set 3 For The Byron-Braidwood LRA (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML13303B463)
December 12, 2013	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Nuclear Station Units 1 and 2, and the Braidwood Nuclear Station Units 1 and 2, LRA - Aging Management, Set 4 (TAC MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML13281A569)
December 13, 2013	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Requests For Additional Information For The Review Of The Byron Nuclear Station, Units 1 And 2, And Braidwood Nuclear Station, Units 1 And 2, License Renewal Application - Aging Management, Set 2 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML13282A369)
December 17, 2013	Braidwood, Units 1 and 2, Byron, Units 1 and 2, Responses to NRC Requests for Additional Information, Set 3, Dated November 25, 2013, Related to the License Renewal Application (ADAMS Accession No. ML13354C055)
December 19, 2013	Braidwood, Units 1 & 2 and Byron, Units 1 & 2 - Response to NRC Requests for Additional Information, Set 5, dated November 22, 2013, related to License Renewal Application (ADAMS Accession No. ML13353A627)
December 19, 2013	Braidwood, Units 1 and 2 and Byron, Units 1 and 2, Updated Responses to Two NRC Requests for Additional Information from Set 1, Dated October 7, 2013, Related to the License Renewal Application (ADAMS Accession No. ML13354B749)
January 13, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 6 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML13317A075)
January 13, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Response to NRC Requests for Additional Information, Set 4, dated December 12, 2013, Related to the License Renewal Application (ADAMS Accession No. ML14013A148)
January 13, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Response to NRC Requests for Additional Information, Set 2, dated December 13, 2013, Related to the License Renewal Application (ADAMS Accession No. ML14013A293)
January 22, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Requests for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 9 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14007A658)
January 23, 2014	Summary Of Telephone Conference Call Held On October 22, 2013, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning RAI Set 4 For The Byron-Braidwood LRA (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML13330A932)

Date	Subject
January 23, 2014	Summary of Telephone Conference Call Held on October 31, 2013, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Draft Requests for Additional Information Pertaining To the Byron Station and Braidwood Station (ADAMS Accession No. ML13309A932)
January 23, 2014	Summary Of Telephone Conference Call Held Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning Draft Requests For Additional Information Pertaining To The Byron Station And Braidwood Station (ADAMS Accession No. ML13318A415)
February 4, 2014	Braidwood, Units 1 and 2 and Byron, Units 1 and 2, Response to NRC Requests for Additional Information, Set 6, Dated January 13, 2014, Related to License Renewal Application (ADAMS Accession No. ML14035A516)
February 6, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Requests For Additional Information For The Review Of The Byron Station, Units 1 And 2, And Braidwood Station, Units 1 And 2, License Renewal Application- Aging Management, Set 8 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14006A021)
February 7, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 13 (TAC MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14023A564)
February 10, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Requests for Additional Information for The Review of The Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 12 (TAC MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14030A596)
February 18, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 And 2, And Braidwood Station, Units 1 And 2, License Renewal Application, Set 11 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14034A068)
February 18, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 And 2, And Braidwood Station, Units 1 And 2, License Renewal Application, Set 17 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14007A603)
February 19, 2014	Braidwood and Byron Stations, Units 1 and 2 - Response to NRC Requests for Additional Information, Set 9, dated January 22, 2014, related to the License Renewal Application (ADAMS Accession No. ML14051A154)
February 20, 2014	Summary Of Telephone Conference Call Held On January 30, 2014, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning Draft Request For Additional Information Pertaining To The Byron Station And Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14035A189)
February 20, 2014	January 22, 2014, Summary of Telephone Conference Call held between NRC and Exelon Generation Company, LLC., Concerning Draft Requests for Additional Information Pertaining to the Byron Station and Braidwood Station, License Renewal Application (ADAMS Accession No. ML14035A534)

Date	Subject
February 24, 2014	Summary of Telephone Conference Call Held on January 16, 2014, Between The U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning RAI Set 7, tor the Byron-Braidwood License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML10450A122)
February 26, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2, License Renewal Application - Aging Management - Set 10 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14038A336)
February 27, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Response to NRC Requests for Additional Information, Set 8, dated February 6, 2014 Related to the License Renewal Application (ADAMS Accession No. ML14058A667)
February 28, 2014	Braidwood and Byron, Units 1 & 2 - Responses to NRC Requests for Additional Information, Set 12, dated February 19, 2014 Related to License Renewal Application (ADAMS Accession No. ML14059A215)
March 4, 2014	Summary of Telephone Conference Call on January 23, 2014, Between U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning RAI Set 11, for Byron-Braidwood License Renewal Application (TAC Nos. MF1879, MF1880, MF1881 & MF1882) (ADAMS Accession No. ML14050A167)
March 4, 2014	Summary of Telephone Conference Call Held on January 28, 2014, Between NRC and Exelon, Concerning RAI Set 10, for the Byron and Braidwood Station, LRA (TAC Nos. MF1879, MF1880, MF1881 & MF1882) (ADAMS Accession No. ML14036A310)
March 4, 2014	Summary of Telephone Conference Call Held on January 29, 2014, Between the NRC and Exelon Generation Company, LLC., Concerning RAI Set 10, for the Byron and Braidwood Station License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14051A431)
March 4, 2014	Braidwood Units 1 & 2 & Byron Station, Units 1 & 2, Response to NRC Requests for Additional Information, Set 13, Dated February 7, 2014 re License Renewal Application (ADAMS Accession No. ML14063A495)
March 4, 2014	Braidwood and Byron, Units 1 and 2 - Response to NRC Requests for Additional Information, Set 11, dated February 18, 2014 related to the License Renewal Application (ADAMS Accession No. ML14063A496)
March 6, 2014	Summary of Telephone Conference Call on January 13, 2014, Between U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC, Concerning RAI Set 8, for Byron-Braidwood License Renewal Application (TAC Nos. MF1879, MF1880, MF1881 & MF1882) (ADAMS Accession No. ML14051A428)
March 7, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Correction to Request for Additional Information B.2.1.10-1, Letter Dated February 7, 2014, for the Review of the Byron Station and Braidwood Station, Units 1 and 2, LRA Set 13 (ADAMS Accession No. ML14050A081)
March 11, 2014	Summary of Telephone Conference Call on February 18, 2014, Between U.S. Nuclear Regulatory Commission & Exelon Generation Company, LLC Concerning Draft Request for Additional Information Regarding Byron & Braidwood Stations, License Renewal Application (ADAMS Accession No. ML14058B180)

Date	Subject
March 11, 2014	Summary of Telephone Conference Call on February 27, 2014, Between U.S. Nuclear Regulatory Commission & Exelon Generation Company, LLC Concerning Draft Request for Additional Information Re Byron Station & Braidwood Station License Renewal Application (ADAMS Accession No. ML14064A403)
March 11, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 15 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14064A391)
March 13, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Response to NRC Requests for Additional Information, Set 7, dated February 18, 2014, Related to the License Renewal Application (ADAMS Accession No. ML14073A118)
March 13, 2014	Aging Management Programs Audit Report Regarding The Byron Station, Units 1 And 2, And Braidwood Station, Units 1 And 2 (TAC Nos. MF1879, MF1880, MF1881, And MF1882) (ADAMS Accession No. ML14071A620)
March 14, 2014	Scoping and Screening Methodology Audit Report Regarding the Byron Station, and Braidwood Station, Units 1 and 2, LRA (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14050A304)
March 18, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 14 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14058B182)
March 20, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2, License Renewal Application - Set 17 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14051A503)
March 21, 2014	Braidwood Units 1 and 2, and Byron Units 1 ND 2 - Updated Responses to NRC Requests for Additional Information, Set 3, dated November 25, 2013, License Renewal Application (ADAMS Accession No. ML14080A187)
March 28, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Responses to NRC Requests for Additional Information, Set 10, dated February 26, 2014 Related to the License Renewal Application (ADAMS Accession No. ML14090A237)
April 3, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 16 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14084A335)
April 3, 2014	Summary of Telephone Conference Call on February 12, 2014, Between U.S. Nuclear Regulatory Commission & Exelon Generation Company, LLC Concerning Draft Request for Additional Information Re Byron Station & Braidwood Station License Renewal Application (ADAMS Accession No. ML14073A705)
April 7, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Project Manager Change for the License Renewal of Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14092A346)

Date	Subject
April 7, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 20 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14092A261)
April 7, 2014	03/04/2014 Summary of Telephone Conference Call Held between NRC and Exelon Generation Company, LLC, Concerning Draft Request for Additional Information Pertaining to the Byron and Braidwood License Renewal Application Set 16 (ADAMS Accession No. ML14084A488)
April 8, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 19 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14094A366)
April 8, 2014	Responses to NRC Requests for Additional Information, Set 15, dated March 11, 2014, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14098A230)
April 10, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 18 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14093B247)
April 14, 2014	Braidwood and Byron Stations, Units 1 and 2 - Response to NRC Request for Additional Information, Set 17, dated March 20, 2014, related to the License Renewal Application (ADAMS Accession No. ML14104A598)
April 17, 2014	Braidwood and Byron, Units 1 & 2 - Responses to NRC Requests for Additional Information, Set 14, dated March 18, 2014, related to License Renewal Application (ADAMS Accession No. ML14107A027)
April 17, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 & 2, and Braidwood Station, Units 1 & 2, License Renewal Application, Set 21 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14099A485)
April 22, 2014	April 03, 2014 Summary of Telephone Conference Call Held between NRC and Exelon Generation Co., LLC, Concerning Draft Request for Additional Information, Set 21, Pertaining to Byron, Units 1 & 2, Braidwood, Units 1 & 2, License Renewal Application (ADAMS Accession No. ML14099A493)
April 24, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 22 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14111A118)
April 24, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 23 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14107A193)

Date	Subject
April 25, 2014	Summary of Telephone Conference Call Held on April 9, 2014, between the U.S. Nuclear Regulatory Commission & Exelon Generation Company, LLC concerning draft request for Additional Information, Set 23, Pertaining to the Byron Station & Braidwood Station (ADAMS Accession No. ML14107A077)
May 5, 2014	October 29, 2013, Summary of Telephone Conference Call Held Between the U.S. Nuclear Regulatory Commission and Exelon Concerning RAI Set 2 for the Byron and Braidwood Station LRA (ADAM Accession No. ML13312A021)
May 5, 2014	Response to NRC Request for Additional Information, Set 16, dated April 3, 2014, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1, and 2, License Renewal Application (ADAMS Accession No. ML14125A325)
May 5, 2014	10 CFR 54.21(b) Annual Amendment to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14125A300)
May 6, 2014	Response to NRC Request for Additional Information, Set 20, dated April 7, 2014, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1, and 2, License Renewal Application (ADAMS Accession No. ML14126A339)
May 6, 2014	Responses to NRC Requests for Additional Information, Set 19, dated April 8, 2014, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1, and 2, License Renewal Application (ADAMS Accession No. ML14126A338)
May 12, 2014	Responses to NRC Requests for Additional Information, Set 18, dated April 10, 2014, Related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14132A139)
May 14, 2014	Summary Of Telephone Conference Call Held On March 26, 2014, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC Concerning Draft Request For Additional Information, Set 21, Pertaining To The Byron Station And Braidwood (ADAMS Accession No. ML14107A226)
May 14, 2014	Summary Of Telephone Conference Call Held On March 19, 2014, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC Concerning Draft Request For Additional Information, Set 18, Pertaining To The Byron Station And Braidwood (ADAMS Accession No. ML14092A440)
May 14, 2014	Summary Of Telephone Conference Call Held On April 10, 2014, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC Concerning Draft Request For Additional Information, Set 22, Pertaining To The Byron Station And Braid (ADAMS Accession No. ML14112A418)
May 14, 2014	Summary of Telephone Conference Call Held on April 1, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 19, Pertaining to the Byron Station and Braidwood (ADAMS Accession No. ML14094A425)
May 14, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Withholding Information from Public Disclosure (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14129A339)

Date	Subject
May 15, 2014	Responses to NRC Requests for Additional Information, Set 21, dated April 17, 2014, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14135A179)
May 19, 2014	Summary of Telephone Conference Call Held on April 22, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 24, Pertaining to the Byron Station and Braidwood (ADAMS Accession No. ML14126A543)
May 19, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 25 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14126A806)
May 19, 2014	Summary Of Telephone Conference Call Held On March 19, 2014, Between The U.S. Nuclear Regulatory Commission And Exelon Generation Company, LLC Concerning Draft Request For Additional Information, Set 18, Pertaining To The Byron Station And Braidwood (ADAMS Accession No. ML14094A275)
May 19, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 24 (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14126A434)
May 19, 2014	Summary of Telephone Conference Call Held on May 6, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 25, Pertaining the Byron Station and Braidwood Station (ADAMS Accession No. ML14133A687)
May 21, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 27 (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14135A540)
May 21, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information for the Review Of the Byron Station, Units 1 and 2, And Braidwood Station, Units 1 And 2, License Renewal Application, Set 26 (TAC MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14133A701)
May 22, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 30 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14136A099)
May 23, 2014	Summary of Telephone Conference Call Held on May 12, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 26, Pertaining to the Byron Station and Braidwood (ADAMS Accession No. ML14133A639)
May 23, 2014	Responses to NRC Requests for Additional Information, Set 23, dated April 24, 2014, related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1, and 2, License Renewal Application (ADAMS Accession No. ML14143A313)

Date	Subject
May 23, 2014	Responses to NRC Requests for Additional Information, Set 22, dated April 24, 2014, related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1, and 2, License Renewal Application (ADAMS Accession No. ML14143A312)
May 23, 2014	Braidwood, Units 1 and 2, Byron, Units 1 and 2, Corrections to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14143A118)
May 28, 2014	Summary of Telephone Conference Call Held on May 15, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, SET 27, Pertaining to the Byron Station and Braidwood (ADAMS Accession No. ML14140A385)
May 29, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 28 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14143A015)
June 4, 2014	Letter to Gallagher, M. P., Exelon Generation Company, LLC: Request For Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 And 2, License Renewal Application, Set 29 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14149A260)
June 5, 2014	Summary of Telephone Conference Call Held on May 21, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 29, Pertaining to the Byron Station and Braidwood (ADAMS Accession No. ML14149A141)
June 5, 2014	Summary of Telephone Conference Call Held on May 19, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 28, Pertaining to the Byron Station and Braidwood (ADAMS Accession No. ML14148A388)
June 5, 2014	Response to NRC Request for Additional Information, Set 25 dated May 19, 2014, related to the Byron Station, Units 1 and 2 and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14157A151)
June 5, 2014	Request for Withdrawal of Documents in accordance with 10 CFR 2.390(c), related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14157A311)
June, 9, 2014	Responses to NRC Requests for Additional Information, Set 24, dated May 19, 2014, related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14160A871)
June 16, 2014	Braidwood, Units 1 & 2, Byron Units 1 & 2, Response to NRC Requests for Additional Information, Set 30 dated May 22, 2014 Related to License Renewal Application (ADAMS Accession No. ML14167A297)
June 16, 2014	Responses to NRC Requests for Additional Information, Set 27, dated May 21, 2014, and Correction of Previously Submitted Information related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14168A084)

Date	Subject
June 17, 2014	Responses to NRC Requests for Additional Information, Set 26, dated May 21, 2014, related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14168A020)
June 17, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 35 (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14160A042)
June 18, 2014	Braidwood Units 1 and 2 & Byron, Units 1 and 2, Responses to NRC Requests for Additional Information, Set 29, dated June 4, 2014, Related to License Renewal Application (ADAMS Accession No. ML14169A026)
June 23, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For The Review Of The Byron Station, Units 1 And 2, And Braidwood Station, Units 1 And 2, License Renewal Application, Set 33 (TACs MF1879, MF1880, MF1881, And MF1882) (ADAMS Accession No. ML14167A547)
June 23, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 34 (TAC MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14167A540)
June 24, 2014	Summary of Telephone Conference Call Held on June 10, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 33, Pertaining to the Byron and Braidwood Station (TAC MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14167A025)
June 24, 2014	Summary of Telephone Conference Call Held between NRC and Exelon Generation Co., LLC, Concerning Draft Request for Additional Information, Set 32, Pertaining to the Byron, and Braidwood, License Renewal Application (TAC MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14162A369)
June 25, 2014	Summary of Telephone Conference Call Held on June 11, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 34, Pertaining to the Byron Station and Braidwood Station (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14164A446)
June 25, 2014	Summary of Teleconference between the U.S. Nuclear Regulatory Commission & Exelon Generation Company, LLC, concerning Draft RAI, set 31, Pertaining to Byron Station & Braidwood, License Renewal Application) (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14175A398)
June 26, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 36 (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14176A090)

Date	Subject
June 30, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 And 2, License Renewal Application, Set 31 (TAC MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14169A627)
June 30, 2014	Response to NRC Request for Additional Information, Set 28, dated May 29, 2014, related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1, and 2, License Renewal Application (ADAMS Accession No. ML14181B145)
June 30, 2014	Request for Extraction of Enclosure D of Exelon Set 10 RAI Response Letter RS-14-084, dated March 28, 2014, related to the Braidwood and Byron, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14181B207)
July 2, 2014	Summary of Telephone Conference Call between NRC and Exelon Generation Co., LLC, Concerning the Byron and Braidwood, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14177A430)
July 7, 2014	Summary of Telephone Conference Call Held between the U.S. NRC and Exelon Generation Co., LLC, Concerning Draft Request for Additional Information, Set 36, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14183B230)
July 7, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 37 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14183B617)
July 8, 2014	Braidwood, Units 1 and 2, Byron, Units 1 and 2, Updated Responses to NRC Set 14 Requests for Additional Information, Related License Renewal Application (ADAMS Accession No. ML14189A094)
July 15, 2014	Resubmittal of Information Associated with NRC Set 10 RAIs, Related to the Byron Station, Units 1 & 2, and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14196A553)
July 16, 2014	Summary of Telephone Conference Call Held between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Request for Additional Information, Set 35, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881 and MF1882) (ADAMS Accession No. ML14191A693)
July 16, 2014	Summary of Telephone Conference Call Held on June 30, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Discussing Applicant Responses in Staff Requests for Additional Information B.2.1.16-1A, B.21.23-1, and 3.0.3-3A Concerning the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14190A464)
July 18, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Responses to NRC Requests for Additional Information, Sets 33 and 34, Both dated June 23, 2014; and Corrections and Clarifications Related to the License Renewal Application (ADAMS Accession No. ML14199A346)

Date	Subject
July 23, 2014	Summary of Telephone Conference Call Held on June 26, 2014, Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 37, Pertaining to Byron Station and Braidwood Station, Units 1 and 2, License Renewal Application (TAC Nos: MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14183A017)
July 25, 2014	Byron and Braidwood Station, Units 1 and 2 - Response to NRC Request for Additional Information, Set 31, dated June 30, 2014, related to the License Renewal Application (ADAMS Accession No. ML14206A920)
July 25, 2014	Braidwood, Units 1 and 2, and Byron, Units 1 and 2, Response to NRC Request for Additional Information, Set 36, dated June 26, 2014, Related to the License Renewal Application (ADAMS Accession No. ML14206A729)
July 28, 2014	Braidwood and Byron Stations, Units 1 & 2 - Response to NRC Request for Additional Information, Set 37, dated July 7, 2014, License Renewal Application (ADAMS Accession No. ML14209A045)
August 4, 2014	Summary of Telephone Conference Call Held on July 16, 2014, Between Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Responses for Request for Additional Information B.2.1.31-1A Pertaining to Byron Station and Braidwood Station, Units 1 and 2, License Renewal Application, Set 38 (TAC Nos: MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14202A396)
August 4, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 38 (TAC Nos: MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14205A595)
August 11, 2014	Summary of Telephone Conference Call Held between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Draft Request for Additional Information, Set 38, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14205A228
August 11, 2014	Summary of Telephone Conference Call Held On June 10, 2014, Between U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Fire Water System Request for Additional Information Responses Pertaining to Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14205A575)
August 20, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request For Additional Information For the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 40 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14232A313)
August 29, 2014	Response to NRC Request for Additional Information, Set 38, dated 08/04/2014; LRA changes from NRR Staff Feedback on 07/30/2014 Telecon; and, LRA changes from NRC Region III IP-71002 Inspection, to Byron, Units 1 & 2, Braidwood, Units 1 & 2, LRA (ADAMS Accession No. ML14241A527)
September 3, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request to Withholding Information from Public Disclosure (TAC Nos. MF1879, MF1880, MF1881, AND MF1882) (ADAMS Accession No. ML14238A691)

Date	Subject
September 4, 2014	Braidwood Units 1 & 2, Byron, Units 1 & 2, Results of Detailed Review Performed in Response to Request 1 of NRC RAI B.2.1.7-7 from Set 17, Related to License Renewal Application (ADAMS Accession No. ML14247A195)
September 4, 2014	Interim Update Related to Earlier Response to Set 29 RAI B.2.1.5-1a, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14247A210)
Sept 5, 2014	Response to NRC Request for Additional Information, Set 40, dated August 20, 2014, related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14248A322)
September 8, 2014	Summary of Telephone Conference Call Held between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Request for Additional Information B.2.1.30-3, 3.0.3-3A, and 2.3.3.12-4, and Draft Request for Additional Information Set 38 and 39, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14238A092)
September 11, 2014	Withdrawal and Resubmittal of Information associated with NRC Set 31 RAIs, related to the Byron Station, Units 1 and 2 and Braidwood Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML14254A143)
September 11, 2014	Braidwood, Units 1 and 2, Byron, Units 1 and 2, Withdrawal and Resubmittal of Information Associated with NRC Set 10 RAIs, Related to License Renewal Application (ADAMS Accession No. ML14254A136)
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October 7, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Withholding Information from Public Disclosure (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession Number ML14266A653).
October 9, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 41 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14279A449)
October 10, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 42 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14282A276)
October 16, 2014	Braidwood and Byron, Units 1 and 2 - Response to NRC Request for Additional Information, Set 41, dated October 9, 2014, and LRA changes resulting from NRC Region III IP-71002 Braidwood Inspection, both related to License Renewal Application (ADAMS Accession No. ML14289A423)

Date	Subject
October 28, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 43 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14300A269)
October 30, 2014	Safety Evaluation Report With Open Items Related to the License Renewal of Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2 (ADAMS Accession No. ML14296A176)
October 31, 2014	Braidwood and Byron, Units 1 & 2 - Response to NRC Request for Additional Information, Set 42, dated October 10, 2014, License Renewal Application (ADAMS Accession No. ML14304A345)
November 6, 2014	Letter to Gallagher M. P., Exelon Generation Company, LLC: Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 44 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML14302A417)
November 6, 2014	Summary of Telephone Conference Call Held on October 7, 2014, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 41, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14300A218)
November 19, 2014	Summary of Telephone Conference Call Held on October 27, 2014, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 44, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14317A783)
November 21, 2014	Braidwood and Byron Stations, Units 1 & 2 - Response to NRC Request for Additional Information, Set 44, dated November 6, 2014, License Renewal Application (ADAMS Accession No. ML14325A744)
November 22, 2014	Braidwood and Byron, Units 1 and 2 - Supplemental Commitment related to the October 31, 2014 Response to NRC Request for Additional Information, Set 42, dated October 10, 2014, related to License Renewal Application (ADAMS Accession No. ML14330A480)
November 24, 2014	Braidwood, Units 1 and 2, Byron, Units 1 and 2, Update Associated with Earlier Responses to Set 29 RAI B.2.1.5-1a, Related to License Renewal Application (ADAMS Accession No. ML14335A323)
November 25, 2014	Braidwood, Units 1 and 2, Byron, Units 1 and 2, Response to NRC Request for Additional Information, Set 43, dated October 28, 2014, Related License Renewal Application (ADAMS Accession No. ML14335A391)
December 4, 2014	Summary of Telephone Conference Call Held on October 7, 2014, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 42, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14323A625)

Date	Subject
December 15, 2014	Braidwood and Byron, Units 1 and 2, Response to NRC Request for Additional Information, Set 35, dated June 17, 2014, and Submittal of an updated License Renewal Commitment List related to License Renewal Application (ADAMS Accession No. ML14349A524)
December 18, 2014	Summary of Telephone Conference Call Held on October 16, 2014, and October 23, 2014, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 43, Pertaining to the Byron Station and Braidwood Station, License Renewal Application (TAC Nos. MF1879, MF1880, MF1881, MF1882) (ADAMS Accession No. ML14343A432)
January 23, 2015	Update to Report the Completion of Commitment 47, Related to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML15023A382)
January 28, 2015	Braidwood and Byron, Units 1 and 2 - LRA Impact Assessment Associated with Earlier Responses to Set 29 RAI B.2.1.5-1a, related to the License Renewal Application (ADAMS Accession No. ML15028A520)
February 6, 2015	Braidwood and Byron, Units 1 & 2 - Update to LRA Section 4.3.4, Class 1 Component Fatigue Analyses Supporting GSI-190 Closure, Related to License Renewal Application (ADAMS Accession No. ML15040A179)
February 11, 2015	Braidwood and Byron Station, Units 1 & 2 - LRA Amendment Providing Commitment for Control Rod Drive Mechanism Examinations, related to License Renewal Application (ADAMS Accession No. ML15042A133)
February 23, 2015	Braidwood, Units 1 & 2 and Byron, Units 1 & 2, Response to NRC Request for Additional Information, Set 45, dated January 22, 2015, Related to License Renewal Application (ADAMS Accession No. ML15054A030)
February 24, 2015	Summary of Telephone Conference Call Held on January 7, 2015, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 45, Pertaining to the Byron Station and Braidwood Station (ADAMS Accession No. ML15029A694)
February 24, 2015	Summary of Telephone Conference Call Held on January 27, 2015, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Draft Request for Additional Information, Set 47, Pertaining to the Byron Station and Braidwood Station (ADAMS Accession No. ML15029A704)
February 25, 2015	Summary of Telephone Conference Call Held on January 29, 2015, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC Concerning Draft Request for Additional Information, Set 46, Pertaining to the Byron Station and Braidwood Station (ADAMS Accession No. ML15033A059)
February 27, 2015	Byron, Units 1 & 2 - Response to Request for Additional Information Regarding Pressure and Temperature Limits Reports (ADAMS Accession No. ML15058A068)
March 3, 2015	02/05/2015 Summary of Telephone Conference Call No. 2 Held between the NRC and Exelon Generation Co., LLC Concerning Request for Additional Information, Set 45, Pertaining to the Byron and Braidwood, License Renewal Application (ADAMS Accession No. ML15051A361)
April 2, 2015	Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application – Set 48 (TAC Nos. MF1879, MF1880, MF1881, and MF1882) (ADAMS Accession No. ML15089A110)

Date	Subject
April 6, 2015	Second 10 CFR 54.21(b) Annual Amendment to the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML15096A409)
April 13, 2015	Braidwood, Units 1 and 2, Byron, Units 1 and 2 - Response to NRC Request for Additional Information, Set 48, dated April 2, 2015 (ADAMS Accession No. ML15103A687)

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 lists the references used throughout this safety evaluation report for review of the license renewal application (LRA) for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2.

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